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BEST PRACTICE REVIEW

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R&D and technology exploitation for CO_2 sources, capture, transportation and geological storage

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EUROPEAN CARBON DIOXIDE NETWORK

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1 CONCLUSIVE SUMMARY

A Best Practice is a technique or methodology that, through experience and research, has proven to lead, efficiently and reliably, to the desired result. This document provides an initial review of Best Practices in the field of CO_2 Capture and Storage (CCS), based mainly on the experience of European research and development programmes. Typically, there is not one practice in any particular area of CCS that has emerged as clearly being the best.

The conclusions are presented here in terms of the individual components, namely fuel type, power cycle, CO_2 separation, CO_2 transportation and geological storage. Although some of CCS is based on mature technology, for some significant components of the technology, maturity is perhaps the exception rather than the rule.

Three areas of CCS practice are considered in this document:

1. Designing and planning a CCS system
2. Operating a CCS system
3. Cessation of injection and managing the geological storage site post-injection

1.1 Designing and planning a CCS system

Decisions in the design phase include choice of type of plant to be fitted with capture, choice of capture technology, type of fuel to be used, etc. If capture is to be fitted to an existing emitter of CO_2, decisions will be made about whether to scrap the existing plant, even though it has useful service life remaining, or retrofit capture to the plant, with concomitant reduction in efficiency. This decision will be determined by many, local factors, as will choice of fuel for the plant.

Two approaches to estimating overall product costs are recognised - “bottom-up” and “top-down”. These analyses are useful for different purposes – the bottom-up analysis is used typically for making decisions about options for an individual plant. Top-down analysis is used for informing decision making by, for example, governments when considering policy options, or electrical power generating companies, that can choose its portfolio of fuels and plant as it sees best.

1.1.1 Capture

Capture process available on the market can easily provide high purity CO_2 (>98%) but there may be some benefit from accepting a lower CO_2 purity if other gases might be co-captured at the same time. There is no general rule about the value of this – it depends on issues such as enhanced corrosion in the transportation system and the acceptability of injecting impure CO_2 underground, as well as the economics of capture.

CO_2 capture is a very mature technology, with over 60 years experience in the upstream oil and gas and petrochemical industries. A key difference between most of those applications and the use of this technology in power plants is that the latter may involve operation in an oxidising atmosphere, with consequent danger of solvent degradation. Several proprietary gas scrubbing systems (physical or chemical absorbents and absorption/desorption towers and related equipment) are commercially available, some with long track record.

The general challenge for each of the CO_2 capture strategies is to minimize the amount of energy used to drive the capture process itself. No single system is best for all situations. New proprietary systems promise improvements for certain flue gas scrubbing processes but these improvements are only incremental.

Whilst post-combustion capture has been demonstrated with coal combustion in a number of commercial installations, there is prospect for improvement in both this and the pre-combustion method, e.g. in an integrated gasification combined cycle power plant (IGCC).

Because natural gas is readily available with insignificant amounts of impurity, it is amenable to processing using membranes. Solvent-based capture processes have been used post-combustion with natural gas power plant; neither pre- nor post-combustion has a clear cost advantage over the other although pre-combustion would probably involve smaller plant.

Use of biomass for heat and/or electric power generation with capture of CO_2 can make biomass a net sink of CO_2 but the cost of such systems is high. CO_2 capture and storage may be used to reduce CO_2 emissions from CO_2 sources in the transport sector by production of a zero-carbon energy carrier such as hydrogen or electricity.

A measure of CO_2-emission abatement costs is to relate these to the amount of emissions avoided but this can be deceptive because of possible confusion arising from choice of the base-case plant. Instead it is better to present costs in terms of cost per unit amount of product (e.g. electricity, hydrogen, ammonia, etc.) coupled with emissions per unit of product.

1.1.2 Transmission of CO_2 and Geological Storage

A geological storage site can be chosen on the basis of a number of considerations involving transport of CO_2 and features of the storage site. A Decision Support System will be useful in the early planning of regional transport and storage. If there are several point sources feeding the same CO_2 store, there will be need for an optimisation to match sources to candidate storage sites, usually trying to minimise transport costs of the captured CO_2.

Estimating the storage capacity and the risk profile of a candidate storage reservoir will involve detailed mapping of the geosphere, numerical modelling of the movement of injected CO_2 into the reservoir and estimation of the risk of seepage from the candidate reservoirs. There will be a trade-off between the different types of reservoir in a region – those in areas with high density of existing wellbores will have higher overall risk of leakage than more “virgin” regions. Use of CO_2 for EOR will have lower net-storage benefit (in the long-term) than injection into aquifers. However injection into existing hydrocarbon fields can be done with more confidence due to the better-defined nature of the geological structure.

The potential benefit of longer transport distances must be weighed against the additional CO_2 produced during the transport itself. This is best done using life-cycle analysis.

1.2 Operating a CCS system

1.2.1 Capture, transmission and storage

The operation of the capture plant will be covered by the practices put in place by the vendors of the equipment and by the operators of the plant, as will the operation of the pipeline and/or ship transport of CO_2.

The operation of CO_2 geological storage sites can benefit from the experience and practice of the natural gas storage industry to prevent fracturing the storage reservoir by over-pressuring. Similarly the CO_2 EOR industry, which has been operating for 30 years, has established a large amount of relevant experience about injecting CO_2. One commercial-scale CO_2 geological storage site has been operated so far, the Sleipner Saline Aquifer CO_2 Storage (SACS) project, so experience from this project dominates fit-for-purpose practices for CO_2 geological storage.

If a CO_2 blow-out occurs, its effects can develop so quickly that personnel have insufficient time to react to prevent it, unlike blow-outs in hydrocarbon wells, so such events should be included in risk assessments, for safety reasons if not for security of storage.

Underground storage of natural gas indicates that it is best practice to avoid fracturing the storage reservoir by injecting at pressures higher than the mechanical strength of the reservoir rock.

1.2.2 Monitoring

Monitoring the capture and transportation systems (surface facilities) will be covered by Best Practice already established by the industry and no further information has been collected here on this. Monitoring of the injected CO_2 in the storage reservoir is a bigger challenge. Offshore storage projects must consider the SACS experience to be the closest to Best Practice for seismic monitoring of injected CO_2. As the injected CO_2 plume naturally disperses and dissolves it will become increasingly difficult to detect using any method over time. In natural gas storage, monitoring of overlying aquifers is used to detect long-term leakage.

2 INTRODUCTION

The starting point for identifying Best Practices is to clearly state what is meant by a Best Practice. The definition used in this document is as follows: a Best Practice is a technique or methodology that, through experience and research, has proven to lead efficiently and reliably to the desired result. Some aspects of using this definition are described in section 2.1 followed by a discussion of the goals of this review in 2.2. High-level practices for CO_2 Capture and Storage (CCS) are briefly described in section 2.3. Some division of the high-level practices into lower-level practices is included.

The basis for this review is existing research and development programmes, mainly in Europe. Consequently the practices identified are more concerned with R&D than with operation of commercial CCS facilities – however there are several lessons about operation of such facilities which have been recognised in these projects. It is beyond the scope of this review to describe in detail all of the research and development programmes on CCS which have been performed, are in progress or planned in the near future. However, the structure of CO_2NET2 has provided access to EU supported programs in this area, so the main learning from these projects have provided a basis for the practices described here; the projects themselves are summarised in section 7.

The detailed information on the rest of the CO_2 research programmes outside Europe is mostly available through the CO2NET website.

Much of the practices related to CCS are either the subject of research or are undergoing pilot tests. Therefore there is typically not one practice in any particular area that has emerged as clearly the best; for ease of use, the following discussion is generally presented in terms of the individual component technologies rather than the whole system. Thus, this document attempts to define the main practices involved in CCS, and any best practices that have been identified.

2.1 General Definition of Best Practice

A Best Practice is a technique or methodology that, through experience and research, has proven to lead efficiently and reliably to the desired result.

A commitment to using the Best Practices in any field is a commitment to using all the knowledge and technology at one's disposal to ensure success.

A Best Practice tends to spread throughout a field or industry after a success has been demonstrated. However, it is often noted that demonstrated Best Practices can be slow to spread, even within an organization. According to the American Productivity & Quality Center, the three main barriers to adoption of a Best Practice are a lack of knowledge about current Best Practices, a lack of motivation to make changes involved in their adoption, and a lack of knowledge and skills required to do so. This review is a contribution to addressing the first of these barriers in the field of CCS.

2.2 Goals of this Review

It is hoped that this review will start the process of identifying the Best Practices at the top-level of CCS as related to fuel, power cycle, CO_2 separation, CO_2 transportation and geological storage. It is also the ambition of this review to identify Best Practices in related areas as far as possible.

One exclusive Best Practice for CCS will never exist that will fit all the different needs of all users and situations, even after several alternative fit-for-purpose technologies have demonstrated an acceptable level of reliability, maturity and availability. For some significant components of CCS technology today, maturity is perhaps the exception instead of the rule.

2.3 The Main Practices Related to CO_2 Capture and Storage (CCS)

The three areas of CCS practice that are considered in this document are:

1. Designing and planning a CCS system
2. Operating the CCS system
3. Cessation of injection and managing the geological storage site post-injection

In view of the fact that CCS was only proposed for use in mitigation of climate change within the last decade or so, it is not surprising that there are no formal examples directly related to the last of these 3 categories.

The next three sections of this document are organised according to these three CCS practices.

3 DESIGNING AND PLANNING A CCS SYSTEM

3.1 Choosing a CO_2 Capture Technology

One of the first decisions to be made concerns choice of capture technology, which will take account of the situation within which capture is to be employed, the many needs of the plant, whether it is an existing plant or one under planning or construction, the type of fuel to be used, etc.

It should be noted that a number of industrial plants already produce a relatively pure CO_2 stream that requires minimal additional effort (i.e. compression and transportation to underground geological storage). A large number of such installations have been identified and recorded in a database of CO_2 point sources [IEA GHG 2002]; the ability to link such sources with oil fields needing CO_2 for Enhanced Oil Recovery (EOR) would offer low cost opportunities for CCS, which may provide some of the first examples of the use of such technology. Initial examples are natural gas fields where CO_2 is separated for commercial reasons (i.e. in order to be able to meet market specifications on the gas) – these include Sleipner Vest, K-12B, In Salah and Snøhvit.

3.1.1 Newbuild (greenfield) versus Retrofit (brownfield)

For existing emitters of CO_2 the decision about using CCS is essentially:

1. Scrapping an installation that has useful service life left but replacing it with probably superior technology including the ability to capture CO_2, compared with
2. Retrofit of capture to the existing installation, with reduction in efficiency but exploiting the remnant life of the existing plant whilst having to amortise the additional investment over this period, accepting that this may result in less effective CO_2 capture.

Power generating facilities with sufficient remaining life times will naturally be considered for retrofit to reduce CO_2 emissions, as this may be more attractive than scrapping and complete replacement at the time. In any specific case, there will be a range of retrofit options, ranging from minor upgrades to wholesale re-powering, which is probably the closest analogy for CCS. A good example of a comprehensive re-powering of the combustion process is the Wabash River Repowering Project in Indiana (USA). This plant was built at the “mouth” of a coal mine in the 1950s, and was converted to a modern coal gasification plant in the 1990s as part of a US DOE supported project within its Clean Coal Technology programme. The retrofit improved effective electrical generation from 33% to 40% (HHV) using modern coal gasification process[*].

3.1.2 Choice of fuel

The type of fuel is an important aspect of decisions for reducing emissions from a plant. The world is dependent on fossil fuels for more than 85% of its delivered energy at present and it is very hard to see how this situation could be changed quickly. This indicates that, if CO_2 emissions are to be reduced by a substantial amount, as indicated by many authors, use of CCS with fossil fuel combustion will be an important option to have available.

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[*] See the official DOE web site http://www.lanl.gov/projects/cctc/factsheets/wabsh/wabashrdemo.html Note that this plant does not have CO_2 capture but this could be fitted by incorporating a few extra items of process equipment to modify the fuel gas produced so as to produce a stream of relatively high-concentration, high pressure CO_2.

The particular fossil fuel to be used will be a matter for local decision. For example, a large part of the world will probably continue to use local coal as the primary source of heat and electricity generation for many years to come, due to its availability, resource longevity and supply security. For other countries with natural gas reserves, and a concern about emissions, there will be interest in means of capturing CO_2 from use of this fuel. In other cases, countries will be importing fuel – both coal and natural gas are internationally traded commodities and so means of using them without substantial emissions will also be important to countries without indigenous resources.

3.1.3 Selection of Capture Plant

Because plants typically have a useful life of 20-50 years, the effects of fuel availability and relative fuel price development (natural gas versus oil versus coal versus biomass, etc.) must be included when comparing the relative costs of the product (whether it be electricity or some other product).

Two approaches to estimating overall product (electricity, cement, fertilizer, etc.) costs that include CO_2 capture are recognised, the “bottom-up” and the “top-down”. One investigator has combined these approaches [McFarland et al. 2002]. These analyses are useful for different purposes – the bottom-up analysis will be used typically for making decisions about options for an individual plant. Top-down analysis is used for informing decision making by, for example, governments when considering overall resource availability, policy options and need to understand the implications of different means of meeting policy goals.

3.1.3.1 Bottom-up Analysis of a Capture Plant

The bottom-up analysis consists of a set of cost and income flows based on process simulation. The inputs to the process will include:

- Fuel type and consumption
- Other necessary supplies such as air, oxygen, water, sulphur treatment materials, solvents, corrosion inhibitors, emulsion inhibitors, etc.
- Operating conditions of the main components in the process, including external flows of air, water, etc. for the cooling system
- Boundary conditions of the process

The outputs of the process will include

- The product, which may be electricity or some other process stream such as hydrogen or steam
- Emissions in gas, liquid or solid phases

The process equipment will have associated capital, maintenance and operating expenses which are estimated from the process simulation. With appropriate assumptions about fuel costs, discounted cash flow calculations are performed which give a set of economic indicators for the unit. The bottom-up approach is widely accepted as valid for initial engineering feasibility and design studies for comparing design choices.

There are a number of process simulation models for bottom-up analysis of process plants referred to in the CO_2 capture literature, e.g. AspenPlus (Aspen Technology, Inc.), HYSYS (Hyprotech, Ltd., a division of Aspen Technology.), GTPRO (Thermoflow, Inc.), PRO/II (Simulation Sciences, Inc.), Integrated Environmental Control Model (IECM, public domain software available through Carnegie Melon University[*]). Applying this type of software package can be considered best practice for a bottom-up analysis.

At an even more fundamental level, Computational Fluid Dynamics (CFD) simulation software may be used to model flows and reactions within an individual process unit. This may be more relevant for capture processes which are still in development such as the oxyfuel combustor. Fluent (Fluent, Inc.) and AspenPlus have made available an integrated package for total process simulation. It is not known to what extent reported results on different capture process concepts and designs have integrated their process simulations.

The weakness of the bottom-up analysis is that in the long term, fuel prices will change - for example, increased demand for natural gas will ultimately increase its cost because natural gas resources are finite and have relatively high transport costs over long distances. In other words, the realised costs for owning and operating a given type of plant depend to a significant degree on macro-economic effects outside the control of the individual plant owner. This is especially an issue when projecting over the 30 years or more that a plant may be expected to operate.

3.1.3.2 Top-down Analysis of a System

Top-down models typically represent technology using aggregated production functions for each sector of the economy. For example, electricity production may be treated as a single sector with capital, labour, material, and fuel inputs. Continuous substitution can be made between inputs (e.g. between gas and coal, or between fuels and capital). The particular focus of the top-down approach is on market and economy-wide feedbacks and interactions, often sacrificing the technological description of the bottom-up approach [McFarland et al., 2002[†], who developed a top-down model as part of a research project]. Because of the use of these models for planning and long-term decision making, they tend not to be available commercially but are developed for the particular user's requirements. However, top-down models may not be any better at representing long-term fuel costs than bottom-up models as both rely on assumptions about the future and on resource availability, for which data is often subject to considerable uncertainty.

3.1.3.3 Choice of CO_2 Stream Purity

One of the key challenges in designing a capture plant will be to choose the optimal CO_2 purity. The capture process available on the market can easily provide high CO_2 purity (>98%). The issue is whether there may be some overall benefit by accepting a lower CO_2 purity if other gases might be co-captured at the same time. However, this is not simply a matter of design parameters for the capture process – it is also necessary to consider the effect that other gases could have on possible corrosion in the transport system, as well as increased risk due to toxic leaks at the plant and from the transportation system, as well as the acceptability of injecting mixtures of gases underground. There may be different views about this in different parts of the world[‡].

A capture option for coal power plants may be to use an absorbent that captures CO_2 and one or more of the other flue gas components, e.g. SO_x, NO_x and mercury [Tarka et al. 2004]. However, the amount of CO_2 captured from the flue gases of the coal plant in this way may be less than for other absorbent systems.

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[*] See website http://www.iecm-online.com/ .

[†] This reference used the MIT Emissions Predictions and Policy Analysis model (EPPA), which is a recursive dynamic general economic equilibrium formulation based on input from a comprehensive energy-economy data set called GTAP-E.

[‡] For example in Canada, acid gases have been injected underground for several decades, principally as a means of disposing of sulphur. This is described later in this report.

3.1.4 Maturity of Different Capture Process Types

The history of CO_2 capture (i.e. separation of acid gases) goes back 60 years for the upstream oil and gas and petrochemical industries. One of the key components of CO_2 capture technology used in these plants, and in connection with gasification of coal or bitumen or asphalt, is that these typically provide a reducing atmosphere for the separation process. Thus much of the experience of this highly developed and rapidly expanding commercial technology is in a different environment than the oxidizing atmosphere likely to be found in many power plant applications. Before going into the types of CO_2 capture processes, this section summarises the different industries that have used separation techniques similar to those used for CO_2 capture.

For many years, the upstream oil and gas industry has been separating naturally-occurring CO_2 from raw natural gas production streams for the purpose of creating sales gas of sufficient purity. Such CO_2 separation operations in natural gas production occur world-wide scale and are growing in number as more super giant natural gas reservoirs with significant natural CO_2 content (and in some cases H_2S content as well) are being developed (e.g. South Pars/North Field, Gorgon, Natuna, etc.). If these gas fields are fully developed, they will produce as much as 20-40 million tons CO_2 yearly together with the natural gas[*].

The process of capturing CO_2 from a combustion unit, either before or after combustion, has some similarities to the above but also some additional challenges relative to capture of CO_2 from natural gas streams. Three CO_2 capture plants based on amine scrubbing of power and boiler plant flue gases were installed in the 1970s and 1980s [Herzog, 1999] in order to concentrate CO_2 for injection in oil reservoirs for increasing oil recovery (EOR). However, these plants were closed as oil prices fell, and now there are no such plants in operation[†]. In such applications, precautions have to be taken to ensure the capture solvent is not degraded too fast by oxidation. The inhibitors are mainly proprietary. Several power plant use CO_2 capture to produce a pure CO_2 stream for use in carbonated drinks – in these plant, only a small fraction of the CO_2 available in the whole flue gas stream is extracted.

Other types of industrial production plant capture a CO_2 stream today [IEAGHG 2002]. A feature common to these plants is that the CO_2 must be removed in order to produce a pure "product" which may be ammonia, hydrogen, ethylene, etc.

3.1.5 Classification of Capture Processes

The range of different CO_2 capture process techniques has been organised by CO_2NET2 Work Package 4 as shown in table 3.1 below. The explanations and descriptions of the various techniques can be found in a number of references and will not be covered in this document. The general challenge of each of the CO_2 capture strategies is to minimize the amount of energy used to drive the capture process itself, which represents 15%-35% of the net energy output of the plant without CO_2 capture, depending on the process type, design, etc.

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[*] This is geologic CO_2, not anthropogenic, i.e. it does not include the CO_2 that would be emitted by the refrigeration plants required to convert the gas to LNG for transport and subsequent re-conversion to pipeline temperature and pressure. Nor does this include the CO_2 resulting from combusting the natural gas at the end use.

[†] When oil prices again rose, natural geological reservoirs of pure CO_2 were since discovered and proved to be more cost-effective sources of CO_2 for EOR. About 20% of the CO_2 used in EOR projects is however a bi-product of either natural gas processing plants or ammonia plants [Stevens et al 2000].

Table 3.1: Taxonomy of CO_2 capture techniques (from CO_2NET2 Work Package 4)

Capture method	**Post-combustion decarbonisation**	**Pre-combustion decarbonisation**	**Denitrogenated conversion**
Principle of separation			
Membranes	• Membrane gas absorption • Polymeric membranes • Ceramic membranes • Facilitated transport membranes • Carbon molecular sieve membranes	CO_2/H_2 separation based on: • Ceramic membranes • Polymeric membranes • Palladium membranes • Membrane gas absorption	• O_2-conducting membranes • Facilitated transport membranes • Solid oxide fuel cells
Adsorption	• Lime carbonation/calcinations • Carbon based sorbents	• Dolomite, hydrotalcites and other carbonates • Zirconates	• Adsorbents for O_2/N_2 separation, perovskites • Chemical looping
Absorption	• Improved absorption liquids • Novel contacting equipment • Improved design of processes	• Improved absorption liquids • Improved design of processes	• Absorbents for O_2/N_2 separation
Cryogenic	• Improved liquefaction	• CO_2/H_2 separations	• Improved distillation for air separation
Carbon extraction	Not applicable	• Direct decarbonisation	Not applicable
Principle of energy conversion	• Novel power cycles	• Hydrogen in gas turbines	• Combustion in O_2/CO_2 atmosphere

Several proprietary gas scrubbing systems (physical or chemical absorbents and absorption/desorption towers and related equipment) are commercially available, some with long track records [Herzog 1999, McKee 2002]. Gas scrubbing systems are optimised for a number of project specific parameters. No one single system is best for all situations, and new proprietary systems promise incremental improvements for certain flue gas scrubbing processes [Wilson 2002].

The greatest potential technical performance improvement for chemical absorption systems is to decrease the energy necessary to strip CO_2 from the saturated absorption stream (regeneration of absorbent).

Post-combustion chemical absorption systems which use amines are susceptible to degradation due to oxidation and exposure to other non-CO_2 components in flue gases from traditional coal combustion. Proprietary inhibitors and novel solvents have been developed to enable these solvents to be used for post-combustion scrubbing of coal plant flue gas. The International Test Centre for CO_2 Capture at the University of Regina in Saskatchewan is dedicated to comparing different flue gas scrubbing processes. This centre has both pilot-scale experimental rigs and access to an existing direct-fired coal power plant (at Boundary Dam) [Wilson 2002].

The Japanese power plant industry has collaborated with a process developer on development of flue gas scrubbing absorption technology, including proving the systems on a pilot plant in

Osaka [Mimura et al 2000]. Proprietary amine solvents are now on the market from this development.

The practice of choosing a flue gas scrubbing system is very dependent on the type of fuel and combustion process used. Therefore the next sections discuss some of the practices for each fuel type.

3.1.6 Choosing Capture Technologies depending on type of Fuel/Energy Carrier

Capture technology is intimately related to fuel type. As discussed above, some countries/regions have greater flexibility regarding choice of fuel than others. Fuel switching from coal to natural gas has already provided substantial reductions in CO_2 emissions in the United Kingdom.

Coal

Coal will always require considerably more effort in processing to reduce its overall emissions than oil, natural gas or biomass but the local availability of large quantities of coal make it appear to be low-cost for long periods of time even when considering its higher requirement for scrubbing for sulphur, mercury, etc.

Whilst post-combustion capture has been demonstrated with coal combustion in a number of commercial installations, there is prospect for improvement in both this and the pre-combustion method, which is the method used in an integrated gasification combined cycle power plant (IGCC). Sulphur scrubbing is already required for coal plant in North America, Western Europe and Japan. Coal gasification provides a good basis for removal of sulphur as an alternative to flue gas scrubbing. Future coal power plants that are designed to capture CO_2 could make use of either approach.

Table 3.2 shows some of the current coal-fired integrated gasification combined cycle (IGCC) electrical power plants world-wide. Only one is confirmed to be a technical failure (Pinon Pine in Nevada). These plants can be modified relatively easily to produce a high concentration stream of CO_2 at high pressure by addition of shift reactor and CO_2 separation; this type of plant lends itself well to using proven, commercial physical absorbents.

There exists a number of proprietary licensed coal gasification processes. One or more of these may represent a best practice with respect to conversion efficiency and overall emissions but no attempt was made here to identify which processes are best.

Table 3.2 Some commercial-scale IGCC plants world-wide built to deliver electricity to the grid.

Project	Start Operations	Current status
Buggenum Netherlands	1995	In commercial operation
Polk Power Florida	1996	In commercial operation
Puertollano Spain	1998	In commercial operation
Wabash River Repower Indiana	1995	In commercial operation, 2 MW fuel cell demo planned
Kentucky	2006-2007	Under planning
Pinon Pine Nevada	1998	Shut after numerous attempts to solve start-up problems. Never operated successfully.

In addition, several IGCC plant have been proposed for building in the next decade. Several of these are in Europe – some involve production of a syngas stream rich in CO_2 as part of the basic process (rather than as a means of capturing CO_2 as described above). Although not intended to be built with CO_2 capture, some of these plant may be described as "capture ready" since all that would be necessary to produce a stream of CO_2 for storage would be to modify the gas clean-up process in order to separate CO_2 and compress it for storage. One plant, Future Gen[*] in the USA, would involve capture of CO_2 as a part of the original design.

Natural Gas

Inherent CO_2 emissions from modern combined-cycle natural gas plants (NGCC) are about ½ that of a modern coal plant on the basis of unit electrical power output. In other words, fuel and technology switching from traditional pulverized direct-air-fired coal technology to NGCC gives a significant improvement in CO_2 emissions.

A consequence of the fact that natural gas has lower CO_2 flue gas concentration than coal should mean that the cost of separating CO_2 should be higher than for a coal-fired power plant because the cost of separating a unit of CO_2 capture falls with increasing concentrations of CO_2 in gaseous mixtures. However, abatement costs for capture of CO_2 also depend on the efficiency loss of the plant (less in the case of natural gas as compared to coal) and the extra equipment required (also less in the case of natural gas). Consequently, the abatement costs for capture in natural gas plant are lower than for coal as measured by unit cost per unit mass CO_2 avoided[†], contrary to first impressions.

Because natural gas is readily available with insignificant concentrations of components that complicate the separation process, natural gas is amenable to processing using membranes that

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[*] For more information on the FutureGen project see http://www.fossil.energy.gov/programs/pwersystems/futuregen .

[†] Compared with a similar plant without capture.

are otherwise sensitive to highly reactive components such as sulphur compounds. Solvent-based capture processes could be used either pre- or post-combustion – neither has a clear cost advantage over the other although pre-combustion would probably involve smaller plant.

The catalytic creation of syngas by reforming (normally done by steam reforming), the catalytic creation of CO_2 from syngas (normally done by water-shift reaction) and the separation of hydrogen from the syngas could potentially be accomplished by an integrated catalytic reformer and hydrogen-permeable membrane. This can significantly reduce investment in steam reforming and water-shift reactors and balance of system components, thereby simplifying the overall power generation and CO_2 capture system [Dijkstra and Jansen 2002].

There is a more challenging downside to natural gas, however. Since natural gas requires considerable energy input to transport over very long distances (i.e. longer than pipelines can economically manage), global trade in Liquefied Natural Gas (LNG) is rapidly expanding. The liquefaction process, transport and re-gasification together consume 12-15% of the energy value of the input gas to the transport system. This consumption implies some CO_2 would be produced that is not captured at the final point of use of the natural gas.

No best practice for CO_2 capture of a process using natural gas fuel has been identified, although some of the new process concepts mentioned here promise a step-change improvement in overall energy conversion even when including the capture system.

Biomass

Use of biomass for heat and/or electric power generation results in net CO_2 production close to zero without any form of CO_2 capture as long as new biological material is continuously replacing the harvested plant mass. In this case, electricity produced by biomass plants may be competitive with fossil fuel plants with CO_2 capture and storage [Wahlund et al. 2000] although the availability of biomass and the likely scale of plant may be different.

Co-firing biomass with coal on a commercial basis is now found in approximately 40 pulverised coal-fired power plants worldwide[*]. These plants employ a variety of concepts, from direct co-combustion to indirect co-combustion with pre-gasification and parallel co-combustion, etc. Already there is a wealth of practical experience under a range of conditions and with different feedstocks, e.g. wood, bark, sludge, peat, straw and RDF. Given the existence of modern and efficient coal-fired power plants, cofiring with biomass is a cost-effective, short-term option to substitute fossil fuels and reduce emissions. This also allows the development of fuel flexibility and large-scale biomass supply infrastructures which are needed for future biomass options.

More interesting is the potential of biomass integrated gasification combined-cycle (BIGCC) to produce a relatively pure CO_2 stream that can readily be captured using physical absorbents and subsequently stored. This can make biomass fuel ***a significant net sink of CO_2*** [Rhodes and Keith 2002], in strong contrast to all other fuel types and technologies which, even with CO_2 storage, would at best emit to the atmosphere up to 10-15% of the input carbon as CO_2. The cost of such biomass CO_2 capture systems is high, and therefore may require preferential economic incentives if the electricity cost is to be comparable with fossil fuel plant [Audus and Freund, 2004].

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[*] See http://www.ieabioenergy.com .

Many serious investigators have described designs of a biomass global energy production and conversion system. At least one of them [Faaij et al. 2000] argues seriously for the viability of global biomass production that covers a significant fraction of the world's total power and heat generation needs without displacing food production or further degrading existing wildlife areas.

Other energy carriers

CO_2 capture is a clear option for stationary power production. It is less clear how it can be used to reduce CO_2 emissions from mobile CO_2 sources in the transport sector. Fuel cells hold promise of new efficiency improvements in electrical conversion, and a new possibility for using less carbon intensive energy carriers[*] in mobile applications. This presents yet another new parameter in best practices in capture. Fuel cells can use hydrogen, which can be produced by reforming or gasification processes applied in stationary plants, and these lend themselves to CO_2 capture using the technologies mentioned above. Another example is using ethanol for transport fuel. Ethanol can be produced from biomass by fermentation, a process which allows about 13% of the total carbon to be captured by simply drying and compressing the off-gases from the fermentation tanks [Rhodes and Keith 2002]. This would make the biomass ethanol process the absolutely simplest capture technology achievable. However the energy costs of distilling the ethanol can consume a considerable fraction of the energy content of the biomass feed and, unlike hydrogen, the carbon emissions from end-use are high. Ethanol would be used as a fuel additive for transport, although several large commercial automobile manufacturers produce models that can run on a blend of ethanol and gasoline with as much as 85% ethanol (commonly called FFV, Flexible Fuel Vehicle). Moreover, ethanol-powered automobiles are currently returning to popularity in Brazil where ethanol was once a dominant automobile fuel[†]. Biodiesel from agriculture production is widely available in EU countries as a blend with petroleum diesel (typically 2-5%) although some fleets of vehicles are supplied with essentially 100% biodiesel. No direct CO_2 capture process is known for producing biodiesel, so it is limited to being nearly neutral in its overall CO_2 emissions. The official goal of the EU Biofuels Directive (2003) is that biofuels make up 5.75% of the energy content of all transport fuels by 2010.

3.2 Evaluating and Choosing a CO_2 Geological Storage Site

A geological storage site can be chosen on the basis of a number of considerations. Those that appear to be most important are

- Distance from the point source of CO_2. This can be a major cost driver, especially if pipelines are the main component of transport.
- Capacity of the geological storage reservoir. This must be more than adequate to store all captured CO_2 likely to be made available by the source(s).
- Security of storage – the risk profile of the storage site must be acceptable with respect to health hazards from the major possible leak paths. These risks are also related to the proximity to populated areas and underground sources of drinking water (USDW).

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[*] Energy carriers such as electricity and hydrogen can be manufactured from other fuels and have the key characteristic of emitting no CO_2 at the point of use; other energy carriers, such as methanol or ethanol, emit CO_2 at the point of use.

[†] See for example http://www.planetark.com/dailynewsstory.cfm/newsid/27916/story.htm and http://www.saab.com/main/GLOBAL/en/pressreleases.xml?id=4&type=recent .

- In addition, there is the inherent long-term storage integrity of the geological reservoir. Slow seepage of sufficient CO_2 back to the atmosphere could undermine the original goal of storage, i.e., to reduce atmospheric concentration of CO_2 that can contribute to climate change.
- Net CO_2 stored considered on a life-cycle basis, considering the CO_2-equivalence of other greenhouse gases which may be involved. Using some storage reservoirs will have lower net CO_2 stored due to a number of considerations.

The GESTCO Decision Support System has been specifically constructed to match point sources to candidate geological storage reservoirs in 8 countries in Western Europe. Use of this tool in the early planning phases of regional transport and storage analyses should be considered Best Practice. If there are several point sources feeding the same CO_2 store, there will be need for an optimisation to match sources to candidate storage sites, usually trying to minimise transport costs of the captured CO_2.

3.2.1 Estimating Storage Capacity and the Risk Profile of the Candidate Storage Reservoir

One group of investigators has pointed to a lack of consistent, well-accepted methodology for estimating CO_2 geological storage capacity [Doughty et al 2001] although Manancourt and Gale [2004] have pointed out the reasons for the wide ranges in estimates of storage capacity. There are several important elements of a work process for estimating capacity which include the following:

3.2.1.1 Detailed Mapping of the Geosphere

This should be based on a combination of seismic (both surface and subsurface) data, wellbore data, regional geological studies, geochemical analysis, and core analysis from wellbores where available. The map of the underground should be a digital representation of the 3-D underground structures that can be visualised using the latest mapping software. This work process is a core competency of every upstream oil and gas exploration and production organisation, and this is a major component of the competitiveness of individual companies. Therefore many elements of these work processes are proprietary, and have therefore limited availability for public scrutiny and debate.

3.2.1.2 Numerical Modelling of the Movement of Injected CO_2 into Candidate Storage Reservoirs

Several research and development groups have constructed advanced software for simulation of CO_2 processes in storage reservoirs. Preuss et al. (2002) have published results from a comprehensive comparison of these software packages, and the reader is referred to this work[*]. It should be noted that no single software package is currently capable of including all physical and chemical processes for all storage reservoir types (aquifer, hydrocarbon, coal bed, etc.).

3.2.1.3 Estimating Seepage Risk from Candidate Storage Reservoirs

This process includes input from geosphere mapping, numerical modelling of injected CO_2 and uncertainty analysis of these. The uncertainty analysis includes elements of discrete and continuous probability, as well as use of a selected set of scenarios that represent seepage

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[*] Preuss et al call this simulation code comparison a first step in a process of software development that in 2002 was just in its beginning.

outcomes. Seven different organisations[*] have publicised their particular work processes and tools that focus on estimating seepage risks from specific CO_2 storage sites. Some of these used a public domain database of Features, Events and Processes (FEP) that comprises all risk issues concerning CO_2 geological storage[†]. When identifying risk issues for a specific storage candidate and project, it should be considered to be best practice that the analysis should be assessed against the yardstick of the generic CO_2 storage FEP database to ensure all relevant FEPs have been considered. This process will involve a range of geoscience specialists whose particular focus is on risk sources for seepage, capacity estimation, long-term trapping mechanisms, forward modelling of injected CO_2 plume, etc.

3.2.2 Net CO_2 Stored for Different Types of Geological Storage Reservoirs

Injection of CO_2 into some geological storage reservoirs will allow more oil or gas recovery than would be possible without CO_2 injection. This is advantageous for offsetting the cost of CCS. However, from a life-cycle perspective, this brings more carbon back to the biosphere which will eventually be converted to energy and CO_2, which reduces the overall life-cycle net CO_2 stored. However the extra oil produced will not necessarily add to overall world oil consumption immediately – merely displace more expensive supplies of oil. Thus there is uncertainty about the delay before EOR causes an increase in emissions of CO_2 to the atmosphere. However, it is clear that oil reservoirs which accept CO_2 for EOR will show lower net storage effect compared with aquifers. Enhanced Coal Bed Methane Recovery (ECBMR) and Enhanced Gas Recovery (EGR) lie somewhere in between these 2 extremes.

Compared to producing oil using recovery processes that do not inject CO_2, the storage benefit of CO_2 EOR can be considered to be positive. However, the important distinction here is that the decision maker can choose to store CO_2 in reservoirs that have a true net storage effect, and it is this comparison that is relevant.

Enhanced Gas Recovery (EGR) is a different type of technique where CO_2 is injected early in the life of a gas field (rather than during the declining phase of an oil field's life) in order to maintain production pressure. Eventually CO_2 will break through to the production wells, when there will be a need to separate CO_2 from the well stream. The In Salah field in Algeria will be the first field to re-inject CO_2 in a new field development although K-12B in the Southern North Sea is re-injecting CO_2 into an established field.

In Enhanced Coal Bed Methane Recovery (ECBMR) approximately two molar units of CO_2 injected into the coal bed are believed to produce about one molar unit of methane which, when brought to surface and consumed, produces another molar unit of CO_2. Thus ECBMR may have potential for greater net CO_2 storage than EOR and EGR. However this technique is in its early stages of development and there has been mixed messages from the oldest field (i.e. the Burlington pilot in the San Juan basin).

The relatively long record of acid gas injection in Alberta (Western Canada Sedimentary Basin) indicates that the large-scale CO_2 storage in on-shore reservoirs is feasible [Bachu 2003].

Depleted hydrocarbon reservoirs have proven, well understood storage capacities with a minimum of uncertainty and risk related to updip migration of injected (and buoyant) CO_2. This

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[*] TNO, DNV, Quintessa, Monitor Scientific, Idaho National Engineering and Environmental Laboratory, URS Business Risk Strategies and ECL Technologies all presented studies at the IEA GHG Risk Assessment Workshop on February 11-12th 2004 in London

[†] See website for Quintessa's CO_2 Storage FEP database, http://www.quintessa-online.com/co2

indicates less site surveying may be required, a difference which is reflected in the way that the European standards on natural gas storage treat hydrocarbon and aquifer storage sites.

On the other hand, any reservoirs in a region with high density of wellbores will have higher overall risk of leakage through these “short circuit” paths to surface. Storage in more “virgin” regions with fewer wells may have lower overall risk of leakage or require less effort in site preparation to make secure possibly leaky abandoned wells, so there is a trade-off between the different risks and availability of knowledge of the Geosphere at a specific site.

3.3 Designing a Transport System for the Captured CO_2

Once the CO_2 capture plant and geological storage site are chosen, the next planning task is to design a transport system. The main system components are pipelines, compression facilities, cryogenic facilities, temporary storage facilities, CO_2 tank ships and, in the case of offshore geological storage, offloading units. One of central challenges for transport systems is the purity of the gas stream, i.e., what other gases are present together with the CO_2, because these impurities may amplify corrosion challenges in the presence of free water. The challenges for pipeline systems and tank ships may be different concerning purity of the CO_2 stream.

Regional systems for gathering, transporting and storing CO_2 may be optimised in the planning stage to reduce transport costs. The cost of transport implies using energy, which in most cases will be fossil fuel. Thus transporting CO_2 will create a certain additional quantity of CO_2 that will probably not be captured. Intuitively, a life-cycle analysis (LCA) of the net CO_2 emissions for the whole capture, transport and storage chain must be performed. Any potential benefits of longer transport distances must be weighed against the additional CO_2 produced during the transport itself (which will not be captured). The ISO 14040 standard was developed specifically for life-cycle environmental analyses of either a product or a function, and is probably the closest to a starting point for a best practice for the task of designing an optimum system[*].

The IEAGHG programme commissioned a study to identify available standards, guidelines, recommended practices, etc. in design and construction of CO_2 injection wellbores, storage reservoir management and CO_2 transport systems [IEA GHG Report PH4/23, 2003]. This report also described prescriptive procedures that can be anticipated for permitting, operating and closing of storage sites. The reader is referred to this source for further details.

4 OPERATING A CCS SYSTEM

There are numerous operational aspects of the CCS system. Operating the capture plant will be covered by the practices put in place by the vendors of the equipment and by the operators of the plant but are not available to the authors of this document.

Likewise, pipeline and ship transport of CO_2 are already established by considerable experience collected over the last 30 years in the CO_2 Enhanced Oil Recovery (EOR) industry, the last 80 years by natural gas pipeline industry and the last 40 years of ship transport of cryogenic gases. Transport operational practices are therefore not included in this document.

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[*] The ISO 14040 gives a well-defined framework for performing a general environmental LCA. Other sources of relevant information include the website of Environment Canada (publications on LCA) and the Environmental Protection Agency (EPA) website promoting LCA on health and environmental impact of products, processes and activities.

4.1 Capture Plant Operations

Best practices related to optimised plant operations are technology specific and in general the subject of proprietary commercial solutions. There is a common aspect of plant operations, however, and that is risk assessment of hazardous events. A capture plant will typically be subject to regulations that require assessment of risks to personnel and to inhabitants or others in transit near the plant. Such risk assessments are required for Land Use Planning (LUP) purposes to assure safe distances from possible plant releases or other potentially dangerous events, and to generally keep risks to humans and the local community at an acceptably low level. A variety of assessment techniques are recognised and permitted in different EU countries according to national regulations. Lauridsen et al. [2002] published the results of a European project on the assessment of uncertainties in risk analysis of chemical establishments (ASSURANCE). The project aimed to identify the uncertainties associated with Risk Analysis of major industrial hazards and assessing the way these uncertainties can affect the final outcome of risk studies and of the relevant decisions based on that outcome. In order to achieve this goal, a number of benchmark exercises/case studies were performed by the partners and the results were analysed in a modular and structured way. A reference plant served as the basis for a realistic description of these case studies.

Among the variety of decisions that can and must get a significant input from risk assessment of a plant, those related to LUP in the vicinity of hazardous industrial establishments are probably the most important and difficult ones. LUP decisions are often an issue of conflict among various objectives and interests, influenced by different stakeholders, including the plant operators, the authorities and the general public. The role of the latter has been recognised and expanded in the recently issued framework European Directive for control and management of industrial hazards, the Seveso II Directive. In fact, not only LUP provisions are included in the Directive, posing a clear obligation to planning authorities to consider major accident hazards in the planning process, but also a requirement is put for consultation of the public in land-use and off-site emergency planning.

As the public concern about the protection of human life and the environment increases, land use planning restrictions remain one of the most important controls for managing major accident hazards. The application of the various approaches for LUP and the comparison between them becomes one of the most widely discussed issues.

4.2 Injection System Operations

The situation is somewhat different for operation of CO$_2$ geological storage sites. A closely analogous situation is natural gas (temporary) storage – the industry involved uses prescriptive procedures (often dictated by regulators) that are meant to prevent fracturing the storage reservoir by over-pressuring (which would compromise storage integrity). Other aspects of operating natural gas storage are described in a case study later in this document.

The CO$_2$ EOR industry has been operating for 30 years but its primary goal has been to maximise economic recovery of oil from injection of a limited volume of CO$_2$ rather than to maximise stored volumes of CO$_2$. Nevertheless it has established a large amount of relevant experience about injecting CO$_2$ and much of this constitutes best practice for injection of CO$_2$. A good starting point is the Society of Petroleum Engineers Monograph for CO$_2$ Enhanced Oil Recovery projects [Jarrell et al., 2002], which includes a vast reference list to technical articles in the petroleum engineering literature.

The CO_2 injected into oil fields for EOR is a costly part of the operation so separation of CO_2 from the produced well stream and re-injection is regarded as standard practice for economic reasons. At the time of this writing, only one commercial-scale CO_2 geological storage site has been operated without the goal of increasing incremental recovery of a hydrocarbon resource. Therefore, this experience of this project, the Sleipner Saline Aquifer CO_2 Storage (SACS) project, dominates the area of fit-for-purpose practices for CO_2 geological storage.

The critical item appears to be the wellbore, i.e. those components between the wellhead (where surface flowlines are connected) down to the interface between the storage reservoir. Some examples from operating CO_2 EOR projects are illustrative. Skinner describes in an article [World Oil January 2003] an increase in the number of blow-outs[*] of wells in CO_2 EOR fields in operation in West Texas. Five such blow-outs in the period 2000-2003 are reported, of which four were related to repair/cleaning/modification jobs. Three case descriptions of CO_2 /hydrocarbon blow-outs are described in this article. Common to these three cases is that the CO_2 blow-out occurs in a time frame of seconds due to explosive expansion of supercritical CO_2 to the gas phase, with the result that the rig personnel have insufficient time to react to prevent the blow-out. This is in strong contrast to blow-outs in hydrocarbon wells, in which the time frame is minutes allowing rig personnel time to effectively react to prevent the blow-out by closing safety valves, blow-out prevention, etc.

It is unclear, however, if the risks from blow-outs are different for CO_2 EOR, aquifer storage, EGR and ECBMR. Blow-outs are currently not identified as a source of fugitive CO_2 emissions from geological storage but this evidence indicates that blow-outs should probably be included in any risk assessment, for safety reasons if not for reasons of leakage to atmosphere.

The other area of operation concerning the injection wells is the need to prevent the fracturing of the storage reservoir, e.g. by injecting at pressures higher than the mechanical strength of the reservoir rock. Creation of fractures is a source of risk by allowing CO_2 to migrate out of the storage reservoir, since fractures may compromise the reservoir cap rock seal. Existing standards and practices that regulate operating underground storage of natural gas cover this issue in detail, and are therefore considered to be Best Practice in this respect. What these do not cover is the phenomena related to rapid, dramatic cooling of reservoir rock by injection of cold fluids. This is observed to create a fracture zone around water injection wells in offshore waterflood projects that use sea water, which typically has a temperature 40-80^{o} C lower than that of the formation at the injection/wellbore interface [Slevinsky 2002]. This may be relevant for geological sites that receive cold CO_2 from cryogenic CO_2 transport ships.

4.3 Monitoring an Active CCS System

It will be essential for the operator of a storage site to be able to account for the CO_2 stored underground. Similarly operators of other parts of the chain will need to be able to account for the CO_2 they produce or handle. Various components of these systems may leak, and the leaks must be quickly discovered and repaired. This is important both to prevent harmful dosages of CO_2 for plant operators or other personnel. It will be especially important in a CO_2-limited economy that regulates emissions, to be able to account for fugitive emissions.

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[*] A blow-out is an uncontrolled flow of fluids in a wellbore. It is most dramatic when the fluids reach surface under pressure and are immediately released, escaping to the atmosphere and forming pools on the ground, both of which are highly toxic and explosive in the case of hydrocarbons.

4.3.1 Monitoring the Transport and Injection System

The upstream oil and gas industry has been operating real-time systems to monitor flow rates and pressures at critical points from the down-hole completion to the process system manifold, and it is expected that technology is widely available to implement any prescriptive monitoring. Likewise, the natural gas (temporary) storage industry uses prescriptive procedures (often dictated by regulators) to avoid over-pressuring the reservoir.

Similarly for the capture plant, the various industries already perform comprehensive real-time monitoring of all critical flows, pressures, temperatures, vibrations and in some cases wall thicknesses of critical pipes and vessels. Many process industries also use leak detection using air sensors, which can conceivably be used on selected areas of CO_2 transport systems. No attempt has been made here to identify specific Best Practices for leak detection and prevention on surface facilities.

It is noted that the natural gas production, transport and distribution industries report their own fugitive natural gas emissions to be on the order of 0.5% - 1.5% of the total input to the system (exclusive of emissions at the end user) [Delucchi 2003]. The main sources of the fugitive emissions appear to be chronic leaks from compressors and various leaks at pipe joints, valves and other connections that may be subject to mechanical stresses. This may be indicative of fugitive emissions from a CO_2 transport and injection system in a more mature, operational phase, although such a system will consist mainly of a few large transport trunk lines and not have the large amount of branched distribution pipe work associated with a natural gas network.

4.3.2 Monitoring the Geological Storage Reservoir

Monitoring the injected CO_2 in the storage reservoir is a bigger challenge than the monitoring of the rest of the CCS system. The SACS and the Weyburn projects have pioneered the use of seismic data gathering to infer the shape and size of the injected CO_2 plume in the geological storage reservoir. The SACS project has published a detailed description of their practice of gathering and interpreting seismic data for the purpose of mapping the injected CO_2 plume [Berger et al 2003], and every offshore storage project must consider the SACS experience to be Best Practice for seismic monitoring of injected CO_2. Although other technologies have been suggested as alternatives to seismic, none have proven their technology in a working CO_2 storage system.

For deeper storage reservoirs that are relatively thin, it may be a challenge to extract sufficient signal from the seismic data to detect the density differences due to the injected CO_2 plume [Gupta et al., 2004]. In these cases, monitoring of the plume may require other strategies and methods.

A network of observation wells in the storage reservoir can in theory detect CO_2 as it passes each wellbore, but wellbores are considered to be the greatest risk of seepage to surface over longer time periods [Benson 2003], suggesting that the total number of wellbores in a storage reservoir will inevitably be minimised.

As the injected CO_2 plume disperses, either by dissolving in the reservoir fluids or by spreading as a thin layer of supercritical CO_2 over a very large area, it will be become increasingly difficult to detect using any method. Long after a geological storage site has been plugged and sealed; monitoring will inevitably be focussed closer to the surface, looking for signs of seepage which will be made difficult by the need to distinguish captured CO_2 from the natural background. No best practices have yet been produced for these techniques. Although long-term monitoring is not required by regulators of deep geologic storage of wastes under the rules of the US Environmental Protection Agency [Tsang et al 2001], in the closest analogous situation (i.e. natural gas storage) different approaches are prescribed for monitoring aquifers and for hydrocarbon fields.

5 CESSATION OF INJECTION AND MANAGING THE GEOLOGICAL STORAGE SITE POST-INJECTION

It is expected that the minimum required storage time will be in the order of thousands of years. It is therefore important that the sealed and abandoned wells withstand the corrosive nature of the stored CO_2 for this time in order to prevent seepage back to the atmosphere. A number of practices are currently in place in the upstream oil and gas industry to secure wells post-injection, as well as in industries that dispose of their industrial wastes in geological reservoirs.

However, standard oil and gas field practice does not specify sealing and abandoning wells with materials that can withstand the corrosive nature of supercritical CO_2 and the subsequent carbonic acid. There has also been cast some doubt as to the durability of cement systems currently used for CO_2 injection wells in EOR projects [Duguid et al., 2004]. A need is anticipated for new practices and materials to be developed for well sealing and abandoning that are specially designed to withstand corrosive attack from stored CO_2 and resulting carbonic acid over a period of centuries.

6 BEST PRACTICE CRITERIA

The overall practice of designing, planning, operating and decommissioning a CCS system was very briefly described above. The next question is what factors determine which practice is best among a number of otherwise equivalent practices? What constitutes best practice depends on who is asked. If it is a commercial technology owner and implementer, best practice is what produces the best profitability for the technology owner(s) whilst taking account of risk, meeting current regulations and making appropriate allowance for future regulations. Ideally, this result would coincide with what best fulfils the needs of the other stakeholders, such as government, regulators and the general public, who may wish to reduce greenhouse gas emissions and who ultimately pay for the technology implementation through their electricity bills, fuel bills, etc.

Best practice implies choosing between a set of available alternatives that are mature, proven working systems. Many of the capture technologies are however still under development, but some of them promise step-change improvement in capture efficiency and cost effectiveness. It is important to illustrate the potential of technology development, so these more innovative technologies are included here, although they do not fit the narrow definition of a best practice assessment.

6.1 Best Practice Criteria for CO_2 Capture

A CO_2 capture plant cannot be considered isolated from the production plant it is connected to, because their functionalities are intimately connected. Therefore, the performance metrics used to rank different capture practices must include overall process efficiency of producing electricity, ammonia, etc. as well as metrics for emissions. This section discusses some possible performance metrics for choosing a capture technology solution.

6.1.1 Criteria for CO_2 Capture

Investigators have used several different indicators for comparing CO_2 capture for newbuild plants (greenfield).

One of the most common technical indicators used is change in energy conversion efficiency relative to a base case, which indicates what penalty is introduced by capturing CO_2 in a particular process. New, improved processes will probably have smaller penalty, i.e., higher conversion efficiency, than currently available CO_2 capture technology.

An additional complicating factor is the use of “waste” heat from the plant. Combined Heat and Power (CHP) plants can achieve near 100% total energy efficiency if the waste heat is distributed to local users of warm water [Wahlund 2000]. Because of the different temperatures needed by the district heating and capture processes, the 2 uses are not necessarily incompatible; it can be shown that, for a large combined heat and power scheme supplying district heating, there may be a reduction in the cost[*] of capturing CO_2 compared with a plant which does not supply district heating [IEA GHG Report Ph3/6, 1999].

Another criterion is the technical readiness which may help to differentiate between future technologies and currently available technologies.

6.1.1.1 CO_2 Capture Technical Readiness

This issue is important in two respects. First, 2/3 of the power plant capacity expected to be in operation by 2030 has not yet been built [Hawkins 2003], and can therefore benefit from technology being developed now but which may not be ready in the next 5-10 years. About 1/3 of coal power plants operating in 2004 is expected to be still in operation by 2030. These are obviously candidates for retrofits. If the technology is to be retrofitted, the technology must be ready earlier to reduce emissions from these plants.

6.1.1.2 CCS System Cost Effectiveness and Performance

There appears to be some consensus on the set of unit indicators to be used for comparing different CCS systems, at least for new-build projects [David and Herzog 2000, Audus 2000, Freund and Davison, 2003].

- Efficiency of electrical conversion relative to heat value input of fuel
- CO_2 emissions avoided as a per cent of the CO_2 which would have been emitted by a nominated reference plant without capture.
- Cost of electricity in monetary units per delivered energy unit
- Net CO_2 emission in mass CO_2 per delivered effective energy unit (or some other product, e.g. cement or steel)

Although these authors have all used the unit cost of CO_2 avoided as a measure of performance, this is becoming recognised now as not a good indicator of relative attractiveness, due to the confusion which can arise from different choices of base-case for comparison [Freund and

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[*] Measured in terms of cost of avoided emissions

Davison, 2003]. A better means of comparing the cost of CCS systems is, as indicated above, to examine the cost of unit quantity of product (e.g. electricity) coupled with the CO_2 emissions per unit of product. This gives much less ambiguous results.

Another indicator which may be important is the Specific Investment (i.e. capital cost per unit of plant output capacity). Best practice would be to use consistent system boundaries which would allow comparison of different technologies. However, reliable, verified data for this purpose is very limited. If studies only report results for part of the system, for example the investment required for a given output of hydrogen at a concentration suitable for a properly modified gas turbines, this may, perhaps, not mention the cost of compression of CO_2 or that of the CO_2 export pipeline and injection facility. Thus the results reported for any particular CO_2 capture process should make it clear to the reader if any parts of the whole system are not included in the quoted results.

6.2 Best Practice Criteria for CO_2 Geological Storage

6.2.1 CO_2 Geological Storage Technical Readiness

Injection and monitoring of CO_2 in geological reservoirs has been practiced by the upstream oil industry for the last 30 years, and there is already one example of a field-scale CO_2 storage project in an aquifer, with another starting in 2006, and several other injection projects underway. Clearly the technology is ready once a storage reservoir site has been chosen. The challenge is to screen sites and choose those with an acceptable risk profile weighed against costs of transport from the sources of CO_2.

There are risks in addition to those linked to the nature of the geological storage reservoir. The sources of these additional risks are related to operation of the storage site during the injection phase. Finally, there is a risk related to the quality and integrity of the plugging and abandoning of wells, whether these wells are being used for other purposes passing through the storage zone, or are used for injection of CO_2. The challenges are primarily organisational and compliance issues above and beyond the inherent risk profile of the storage reservoir itself. Every geological reservoir can leak its contents through the actions of hydraulic fracturing (injecting too much at too high pressure) and poor practices post-injection. In other words, the risk mitigation is only half done after the proper geological storage site is evaluated and chosen.

6.2.2 CO_2 Geological Storage Technical Performance

Numerous technical parameters related to the features of the geological storage reservoir have been identified by various investigators. A short list of some of the most important is given here. A factor common to the parameters in this short list is that they can be easily measured, calculated or mapped with relatively straightforward techniques that can have relatively low overall uncertainty.

- Density of stored CO_2 - higher insitu CO_2 density indicates more CO_2 stored per unit reservoir volume. Higher insitu CO_2 density also reduces (over even inverts) the density contrast to the insitu brine and therefore it reduces buoyancy forces relative to the brine. Insitu CO_2 density is ultimately limited by reservoir fracture pressure, which limits injection pressure (CO_2 density is a function of pressure and temperature). Because insitu CO_2 density is limited by reservoir conditions and properties, it can be considered, in a sense, a property of the geological storage reservoir.

- Solubility of injected CO_2 in aquifer water in the storage reservoir, which indicates long-term potential for trapping of the CO_2 in the brine solution. This is a well understood function of storage reservoir temperature, brine composition and storage reservoir pressure. This property is also fixed for a given geological storage reservoir (assuming no alteration of solubility conditions are possible).
- Thickness of cap rock and overlying aquitards, as well as the degree of faulting in sediments above the storage reservoir and cap rock. This is an indicator of inherent geological storage integrity.
- Closure of the hydrodynamic trap, which indicates a bulk pore volume available for CO_2 storage that is not prone to CO_2 migrating updip from the spill point.
- Degree of potential trapping by geochemical processes, i.e., mineralization.

In addition, the following can be considered as indicators of the technical performance of a particular geological storage site. In contrast to the parameters above, these are results of complex interaction of storage reservoir and operations Features, Processes and Events (FEP) [IEA GHG, 2003]. These parameters must be estimated using integrated risk assessment tools. A number of the risk events are related to human behaviour and how operation of the storage sites will comply with the more dynamic limits of the storage reservoirs. Risk of seepage through abandoned wellbores is also a potential contributor to these risk indicators. Although not strictly a part of the geological storage reservoir, abandoned wells must be included here because they are probably the most important sources of seepage risk [Benson 2003].

- Risk of CO_2 escaping from the storage reservoir and contaminating drinking water aquifers[*]
- Risk of CO_2 escaping from storage and leaking to surface in a sudden, catastrophic release that threatens life on the surface
- Risk of CO_2 escaping from storage and reaching the surface over a period of time that may increase the atmospheric concentration of CO_2.

6.2.2.1 CO_2 Transport from Source to Storage Site

Transport of captured CO_2 reduces overall CCS effectiveness due to the energy costs of establishing transport infrastructure and the transport process itself, which are generally met using fossil fuels. It is expected that a trade-off between transport costs and long-term storage security is the primary compromise that will be necessary in most future CCS projects. The obvious place to start is to map CO_2 sources and potential CO_2 storage sites, and this has been done in most of Western Europe including the North Sea, North America including the Gulf of Mexico, Australia and Japan. An arbitrary limit may be placed in these studies on transport from source to storage site [e.g. at 100 km, Lysen et al. 2002], but the Weyburn project transports CO_2 by pipeline over 300 km from source to storage site.

A consistent life-cycle analysis that compares one CO_2 transport solution with another should show the relative amounts of CO_2 that is generated under transport. Use of LCA including emissions should be considered a best practice for planning a transport system.

The goals of CO_2 storage integrity, capacity and permanence may favour the choice of storage site offshore as opposed to onshore. A leak from an offshore storage reservoir will have a high

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[*] CO_2 is not toxic but it would increase acidity and might mobilise any heavy metals present in the aquifer, thereby potentially ruining it as a source of drinking water.

probability of dispersing in ocean water, where it will not affect underground supply of drinking water (USDW) or threaten life on land. However, in shallow seas such as the North Sea (<200 metres depth), the CO$_2$ will not be retained in the ocean but will equilibrate with atmospheric CO$_2$ in a relatively short period of time, which would add to the problem of climate change if this were to happen in a significant quantity.

Another theoretical aspect of storage in geological reservoirs offshore is the possibility that CO$_2$ migrating upwards from the geological reservoir to the sea floor might form a clathrate with pore waters in shallow sediments (also referred to as hydrate). The CO$_2$-water clathrates can form at temperatures below 4-12^o Celsius at pressures higher than 80 bar. These conditions can be found in ocean waters deeper than 800 m but these depths are generally too far offshore to affect the current consideration of storage sites.

Storage in geological reservoirs offshore opens another transport possibility, namely using CO$_2$ tank ships that connect directly to subsea wells for injection. This would add flexibility because some geological storage sites may have short lives due to small storage capacity, where laying a dedicated pipeline to such a site may be suboptimal.

Four CO$_2$ tank ships are currently in service in Northern Europe supplying commercial users of CO$_2$. The issue of an optimal regional transport network of CO$_2$ from point sources to storage sites for a full-scale CCS implementation may include pipelines, hubs, loading terminals, offloading buoys and ships. There is currently one known project looking at approaching the optimisation problem of a regional CO$_2$ infrastructure in the North Sea; this is principally concerned with using oil reservoirs as storage sites for CO$_2$ from Northern Europe, especially CO$_2$ EOR.

7 SUMMARY OF BEST PRACTICE ASPECTS OF CO$_2$NET2 ASSOCIATED PROJECTS

The following programmes cover various aspects of CCS; case studies of Best Practice have been contributed by a number of the project teams. The emphasis in these summaries is on the aspects of these projects that can be considered as contributing to Best Practice on site evaluation, plant design, risk analysis or detailed operational strategy for a CCS site.

7.1 SACS2

The focus of this case study is on the storage system of the Sleipner Vest CO$_2$ injection into a saline aquifer (Utsira formation).

Operation

Injection has now been underway since 1996, at a rate of nearly 1 Mt CO$_2$ /yr. The CO$_2$ is not dehydrated but the injection temperatures and pressures are set to ensure that hydrates do not form that could lead to blockages in the injection well. This procedure had been successful for 8 years running as evidenced by no operational problems with the injection well and also no observed pressure build-up within the reservoir.

Planning

The project recommends that a detailed characterisation of the reservoir and cap rock, both on a local and regional scale, is essential before injection commences. The characterisation should involve a determination of structure and stratigraphy both within and external to the reservoir, together with the physical properties of both the reservoir and cap rock. Key features that the characterisation programme should cover are:

- Identification and mapping of any faults in the reservoir and cap rock (including an assessment of fault sealing capacity and potential for reservoir compartmentalisation). This is necessary to determine the long term fate of the injected CO_2.
- Determination of reservoir properties, such as porosity and permeability - this is required to quantify potential storage capacity and likely migration paths and rates. To determine these properties, the importance cannot be overemphasized of having reservoir rock-core material from the reservoir close to the injection point.
- An assessment of the total reservoir storage potential is desirable, so that a proper injection strategy can be devised.
- An assessment of the natural fluid flow in the reservoir is essential because of its potential to affect the migration of CO_2.
- Also, as injection-induced pressure changes could lead to compromise of the cap rock seal, the possibility of geo-mechanical consequences should be assessed prior to injection.

Design

Experience from SACS indicates that the accuracy to which the structure needs be resolved depends on the structural form of the reservoir into which the CO_2 is injected. If injection is into a large dome structure with closure of several tens of metres or more, CO_2 migration is likely to be well constrained and small uncertainties in reservoir geometry are insignificant. If, on the other hand, the injection is into a reservoir with gentle dips and only minor variations in topography at the upper boundary (as occurs in the Utsira Formation), much more detailed depth mapping will be required. The more detailed mapping is needed to permit the accurate definition of the structure of the top surface of the reservoir to allow the prediction of the overall migration direction and evaluation of the location and volume of any structurally defined traps along the identified migration paths.

Monitoring

One of the major successes of the SACS project was the demonstrated ability to monitor the injected CO_2 using repeated seismic surveying. Even with the CO_2 in a supercritical, rather than a gaseous, state it has been shown that CO_2 accumulations with a thickness as low as about one metre can be detected – far below the conventional seismic resolution limit of approximately 7 metres. Even these thin accumulations of CO_2 were found to cause significant, observable and measurable changes in the seismic signal, both in amplitude and in travel time.

Other monitoring techniques for offshore application have been assessed as part of the SACS project. These included:

- Multi-component (MC) seismic monitoring,
- Gravity surveying,
- Micro-seismic monitoring.

Whilst both MC seismic and gravity surveying have potential benefits, their cost is considered to be a severe drawback for offshore monitoring. For example, offshore a typical MC data set may be between 5 and 10 times as expensive as a conventional 3D survey. Micro-seismicity was also considered to have potential as a continuous monitoring tool but there is a need to determine, first whether micro-seismicity actually does exist. In the Sleipner case, the usefulness of micro-seismicity was questioned because it is more typically used in low porosity carbonate rocks than in sand bodies like the Utsira formation.

Security of storage

The SACS project would recommend that, for any geological CO_2 storage projects, pre-injection reservoir simulation should be carried out with a reservoir model which is based on the best available geological data. Reservoir simulations can predict the CO_2 injection rate that could be maintained, the rise in reservoir pressure caused by the injection, the likely lateral migration of the injected CO_2 and the potential for CO_2 dissolution into the formation water.

The SACS work has shown that existing reservoir simulators (such as Simed II and Eclipse 100) can be applied to model CO_2 migration provided that the physical properties of the CO_2 /brine system are well represented. For all time-scales considered, the density difference between brine and CO_2 and the viscosities are the dominating fluid parameters.

Also, SACS has shown that by monitoring the CO_2 distributions using repeated 3D seismic surveys, quantitative information describing the CO_2 can be obtained by calibrating a simulation model to the development of the seismic images. This information can be used to build larger reservoir models, which can be used for long-term predictions.

Site selection

The SACS project considers that it essential to have a good understanding of the fluid chemistry and mineralogical composition of any potential reservoir and cap rock so as to elucidate their reactivity with CO_2. The degree of reactivity between CO_2, pore water and minerals will influence the long-term storage potential of the formation. Depending on the nature and scale of the chemical reactions, the reservoir-CO_2 interactions may have significant consequences for the CO_2 storage capacity, the injection process, and long-term safety, stability and environmental aspects of CO_2 storage.

The fluid chemistry and mineralogical composition of reservoir and cap rocks will be site specific, so it is considered to be important to recognise that geochemical investigations need to be carried out on a site-by-site basis. Based on the experience drawn from SACS, it is concluded that it is essential to: determine the baseline geochemical conditions prior to CO_2 injection and then determine of the geochemical impact of injected CO_2. In addition, it is concluded that analysis of borehole core material from the cap rock is the only way to provide sufficiently detailed information on cap rock mineralogy and pore water chemistry. The results from SACS indicated that the Utsira sand showed only limited reaction with CO_2. Most reaction occurred with carbonate phases (shell fragments) but these were a very minor proportion (about 3% by weight) of the overall solid material

7.2 WEYBURN

The IEA Weyburn CO_2 Monitoring and Storage Project is a coordinated effort by 20 research organizations in Canada, USA, UK, France, Italy and Denmark, and is co-administered by the Petroleum Technology Research Centre, Natural Resources Canada, Saskatchewan Industry and Resources, the Saskatchewan Research Council, the University of Regina, and IEA GHG. Key objectives of this study have been to investigate the geological, geophysical, and geochemical aspects of the Weyburn field, and map the migration and distribution of existing formation fluids (including resident CO_2) as well as injected fluids.

The Weyburn Oil field is operated by EnCana Energy and lies on the north western rim of the Williston Basin, 16 km south east of Weyburn in southern Saskatchewan. Operations of the oil field began in 1954 and currently there are some 650 production and water injection wells in operation. The average daily crude oil production is 2900 Sm^3/day (ca. 18200 STB/day). Over its lifetime, the field has produced some 55 million Sm^3 of oil from primary and water flood production. The field is currently in production decline having produced in excess of 25 % of the estimated ultimate recoverable oil reserves.

EnCana announced in 1997 that it would develop a CO_2 miscible flood project to extend the life of the Weyburn field by more than 25 years. The project is anticipated to extract an additional 122 million STB of oil from the field. The CO_2 for the project is delivered from the Great Plains Synfuels plant in Beulah, North Dakota, operated by the Dakota Gasification Company through a 325 km long pipeline, supplying 2.7 million Sm^3/day of CO_2 to the Weyburn field. In addition, CO_2 injection and recycle equipment are installed at the Weyburn oilfield.

The key features of this project are briefly highlighted below.

It involves the cross border transfer of CO_2 from the USA to Canada and so is, essentially, the first time there has been international trading of ‘physical’ CO_2 for emissions abatement. With the establishment of the CO_2 gas pipeline infrastructure this will lead to an increased use of anthropogenic CO_2 in EOR projects in the area.

Advanced reservoir mapping and predictive tools are being used to develop a better understanding of the behaviour of CO_2 in a geological formation, including the way that it moves through reservoir rocks, the quantity that can be stored in a reservoir, and how long the CO_2 could be expected to remain trapped in the underground formation.

It is anticipated that 20 million tons of CO_2 will be stored in this manner at Weyburn over the next 25 years. The monitoring project is unique as researchers have been able to collect background information prior to the flooding of the field with CO_2. This has allowed comparison of field characteristics before and after CO_2 injection and has enhanced the understanding of interactions and relationships between oil recovery and CO_2 storage.

The primary benefit of the project has been the objective evaluation, and large-scale demonstration, of the geological storage of CO_2 during EOR operations. The project allowed the testing of a variety of novel techniques to track the movement of CO_2 in the reservoir. The information produced is transferred easily to other locations and allows the effectiveness of the technique and its associated costs to be fully assessed.

The key elements addressed in the project are described here.

This project applied comprehensive geological and hydrogeological characterization of the geosphere at the local and regional scale.

The project has collected samples of reservoir fluids throughout the project for geochemical analysis (major, trace, isotopic, gaseous species), and assessment of geochemical impacts on CO_2 storage integrity and capacity through quantitative modelling. Mechanistic interpretations of gas-water-rock interactions were aided through supporting laboratory autoclave and core-flood experiments.

Movement of various fluids within the reservoir were monitored using 3-D seismic surveys.

Fit-for-purpose techniques and methodologies were developed to investigate caprock and wellbore integrity.

The project refined soil gas sampling and analysis techniques for the monitoring of potential CO_2 leakage in the near-surface.

The project characterised the long-term fate of CO_2 and storage performance using a systems analysis-based assessment methodology, coupled with a comparison of assessment codes.

An economic model for CO_2 storage was assembled including a meaningful demonstration case.

The project organised a number of international workshops to focus on key issues and foster team-building across the interdisciplinary nature of the project.

7.3 EU 6th Framework Projects

Because most of these projects have only recently started, a very brief description of each is given with mention of the main aspects of Best Practice that the projects will focus on.

7.3.1 CASTOR

The project’s objective is to make possible the capture and geological storage of up to 30% of the emissions of large European industrial facilities (mainly conventional power stations). To accomplish this, two approaches must be developed and validated: new technologies for the capture and separation of CO_2 from flue gases and subsequent geological storage, and tools and methods to quantify and minimize the uncertainties and risks linked to the storage of CO_2. In this context, the *Castor* project programme is aimed more specifically at reducing the costs of capture and separation of CO_2 (from 40-60€/ton CO_2 to 20-30€/ton), improving the performance, safety, and environmental impact of geological storage concepts, and, finally, validating the concept at actual sites.

Work on capture, which accounts for 70% of the budget, is aimed at developing new CO_2 post-combustion separation processes suited to the problems of capture of CO_2 at low concentrations in large volumes of gases at low pressure. The processes will be tested in a pilot unit capable of treating from 1 to 2 tons of CO_2 per hour, from real flue gas streams. It will be the largest such installation in the world. This pilot will be implemented in the Esbjerg power station, operated by ELSAM in Denmark.

The work on storage will provide the European industrial community with four new storage facility case studies representative of the geological variety of existing sites across Europe: storage in an abandoned reservoir in the Mediterranean (the Casablanca field, operated by

Repsol, Spain), storage in a deep saline aquifer (Snøhvit, North Sea, operated by Statoil, Norway); storage in two depleted gas reservoirs, one 2500 m deep (North Sea, Netherlands, operated by Gaz de France), and the other closer to the surface and on land, 500 m deep (Austria, operated by Rohoel). Risk and environmental impact studies will be conducted and methodologies for predicting the future of these sites and for monitoring them will be developed, thereby enriching current knowledge in these fields.

The *Castor* project is supported by its partners and a contribution from the European Commission (FP6) for a four-year period. The next big step will be the creation of the pilot capture unit a year from now.

7.3.2 CO_2SINK

The plan is to inject approximately 30 000 tons per year of pure CO_2 into an aquifer below a dormant natural gas storage reservoir about 30 km from the centre of Berlin for a period of approximately 3 years. The source of CO_2 is still under discussion and negotiation.

A dormant natural gas storage reservoir lies at depths between 250 and 400 meters below the surface. The target CO_2 storage aquifer, which lies just below this, has been identified from exploratory wells and seismic data to be about 80 meters thick within a structural closure (a double dome) with the higher apex at a depth of about 600 meters below surface. A closing contour for the domes is located at a depth of some 700 meters. The cap rocks comprise gypsum and clays.

To characterize the underground and understand the in situ processes an array of activities is planned. Detailed analysis of samples of rocks, fluids and microorganisms collected from the underground, measurements and experiments in boreholes, geophysical surveys at the surface, novel monitoring instruments at the surface and down-hole, and numerical predictive models all help to prepare for the injection of CO_2, predict and follow its fate over time and evaluate storage stability and integrity.

The first steps are to prepare a baseline survey of the site and the target reservoir and carry out a detailed risk assessment. The necessary approvals and consent of local authorities and residents will also be sought. This is expected to take 12-18 months. Continued use of the site, to be known as Renergiefarm Knoblauch, is already part of the local authority outline plans which include other experiments on wind, solar and biomass derived energy. The CO_2SINK project will help to support continued use of the existing site infrastructure.

7.4 Other Projects

7.4.1 K-12B: Offshore Re-injection Project

Gaz de France (GdF) operates a natural gas field offshore Netherlands, K12-B, which is in decline but is expected to continue producing for several more years. The natural gas from this field contains 13% CO_2. In order to meet sales specifications, this has to be reduced to 2%. This is done by separating the CO_2, using a methyldiethanolamine (MDEA) scrubber (currently the CO_2 is vented to atmosphere as a 95% pure stream).

Starting in May 2004 the captured CO_2 is being re-injected into the deepest part of the gas field, furthest from the production well, in order to store it in the depleting reservoir. 22 000 tonnes of CO_2 per year is being injected. A comprehensive measurement and monitoring programme will learn about the injectivity of the field and detect possible breakthrough of the re-injected CO_2.

The Netherlands Ministry of Economic Affairs has contracted with GdF to execute this work. GdF will receive around €2 million (excl. VAT) from the Ministry.

7.4.2 Acid Gas Injection in Canada

This section focuses on Canadian experience with acid gas injection (acid gases are typically mixtures containing CO_2, H_2S and other gases), with the main emphasis on transport and geological storage. Experience of the capture systems working with these gases has not been the subject of a detailed review to date.

Transmission system

Design and operation

Pipelines transporting acid gases are usually short, typically 100 to 200m, and generally are constructed of mild steel. Pipelines are designed to minimise the risk of leakage. The acid gas is dehydrated to avoid corrosion which is the main cause of pipeline failures. Dehydration also prevents operational problems associated with hydrate formation that can cause compressor breakdown and plugging.

Pipelines are monitored using a supervisory control and data acquisition (SCADA) system and an Emergency Response Plan (ERP) is required for safety management in the event of a leak. The ERP is discussed in more detail in the next section.

Storage system

Planning

Prospective operators are required to apply for and obtain approval before acid gas injection operations can commence. Applicants are required to submit detailed information regarding surface facilities, injection well configurations, characteristics of the injection reservoir or aquifer, and injection operations. Before approval the applications are reviewed by the regulatory bodies to ensure that they maximize conservation of hydrocarbon resources, minimize environmental impact and ensure public safety. The regulatory bodies concerned with these projects are the Alberta Energy and Utilities Board (AEUB) and the British Columbia Ministry of Energy and Mines. In Alberta, applications for acid gas injection operations must conform to a set of specific requirements given in Chapter 4.2 of Guide 65 that deals with applications for conventional oil and gas reservoirs*. Requirements in British Columbia are modelled on those of Alberta. Regulations framed for acid gas injection should be more stringent than those for CO_2 injection alone, because H_2S is a highly toxic chemical species. However, these regulations provide a useful benchmark for countries that are considering new CO_2 storage projects where no current regulations exist.

Security of storage

Measures contained in the regulations to maintain the integrity of the reservoir include:

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* Alberta Energy Utilities Board, Guide 65: Resources Applications for Conventional & Gas Reservoirs, 2000. This can be found at: http://www.eub.gov.ab/bbs/products/guides/g65.pdf

- A detailed assessment of the regional geology and hydrogeology must be undertaken to select the location of the injection well. This process is designed to evaluate the potential for leakage before approval is granted.
- Knowledge of the geological setting and characteristics is critical to assess the integrity of the host formation or reservoir, and the short-and long-term fate of the injected acid gas. Of particular importance are potential migration pathways from the injection zone to other formations, shallow groundwater and/or the surface.
- The setting of licensed operating limits is a key feature in the regulatory process that is designed to protect the integrity of the injection. The licensed operating parameters include the setting of the following:
    - Maximum well head and bottom hole injection pressures
    - Maximum daily injection rates and maximum overall, total injection volumes.

  The bottom hole injection pressure is set no higher than 90% of the fracture pressure to ensure that fracturing of the cap rock does not occur, but in many cases it is much lower. Typically, the fracture pressures are defined from pressure depth-correlation data for the Alberta basin if site-specific fracture leak-off tests have not been carried out.

Operation

Once the project has commenced the operators have to submit biannual progress reports to the regulatory agencies on their operations giving records of the monitoring of licensed operating parameters, well casing integrity and packer tests etc., Details of the monitoring requirements for the injection well are specified as part of the approval. Typical monitoring requirements are set out in Guide 51[*].

Design

Injection wells are typically considered as Class III wells under AEUB guidelines which covers wells injecting hydrocarbon, inert and sour gases[†]. Class III wells have to be designed to ensure that the acid storage reservoir is isolated from useable water bearing zones.

Possible migration pathways are also an issue in the choice of location of the injection well. However, it is noted that no subsequent subsurface monitoring is required by the regulatory bodies to study whether migration is occurring. This represents current practice in this industry but whether this is relevant to future storage of CO_2 is not clear.

One of the key design features is ensuring operational safety of the injection well. This has to be designed and operated so as to prevent accidental release of the acid gas. In acid gas injection operations, the injection well typically consists of a “string” of steel tubing (i.e. series of connected tubes) with an outer annulus bounded by a steel casing, which is cemented to the subsurface formations. Several safety features are incorporated in the injection well to prevent leakage. The casing is isolated from the string and the acid gas by installing a “packer” in the annulus between the casing and the tubing just above the subsurface storage formation. This is pressure tested for integrity once a year. A down-hole safety valve or check valve is incorporated in the string so that if something fails at the surface, the flow of acid gas from the

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[*] Alberta Energy Utilities Board, Guide 51, Injection and Disposal Wells – well classifications, completion, logging and testing, March 1994.

[†] It is noted in several operations the acid gas is dissolved in the produced water and hence, when injected, the well classification becomes IB or II

formation will be prevented. The well head of the injection well is similarly protected with valves.

Safety

An Emergency Planning Zone (ERP) is required around the injection well in case of an accidental release of acid gas – the ERP area around the injection site should be equipped with H_2S detection and alarm systems, windsocks, self-contained breathing apparatus, and remote unit and plant shutdown stations.

There are two areas where further research is needed:

- The potential for the acid gas to react with the cap rock/well cements and reduce reservoir integrity. Of these possible failure modes, there is considerable concern with regard to the impact that CO_2 alone could have on cements in abandoned well bores. Since many oil and gas fields in Canada are penetrated by significant numbers of existing and abandoned wells, the potential risk of a failure could be high, which could be enhanced by the presence of H_2S. The degree of reaction of the acid gas with the cap rock and injection well cements needs to be fully understood, otherwise there is a risk of compromising the long-term containment of the injected gas.
- Sub-surface monitoring of the injected acid gases would be beneficial to confirm that the gas plume cannot migrate out of the reservoir containment area and hence potentially be able to contaminate overlying drinking water supplies.

7.4.3 Natural Gas Storage

The focus of this section is on the system for temporary storage of natural gas underground.

Standards and Design

A European Standard for gas storage has been developed which provides information relevant to CO_2 storage. The European Standard EN 1918-2:1998 has five parts, which cover surface facilities, and storage in aquifers, oil and gas fields, salt caverns and lined rock caverns. The standard specifies procedures and practices, which are safe and environmentally acceptable. Some of the key points from these standards are summarised below. In particular, those relating to oil and gas fields and aquifers are discussed, because they were considered to be most relevant to CO_2 storage.

The European Standard states that oil and gas fields are preferred for underground storage of natural gas, because their integrity has been proven by hydrocarbon accumulation. Despite the proven nature of the fields the standard requires that the design of the storage facility includes a detailed evaluation of the reservoir. This comprehensive evaluation should include: identifying the trapping mechanism, the structure of the reservoir and its closures, identifying any faults and confirming the integrity of all existing and abandoned wells. It is noted that the techniques for undertaking the evaluation are not prescribed in the standard. The standard assumes that the required information will be available from production operations; if not, it requires that the additional data be collected.

The European Standard for gas storage in aquifers is more extensive than that for oil and gas reservoirs – it is clear from the language of the standard that there is less confidence in the long-term integrity of aquifers as natural gas stores. A number of studies are considered by the European Standard to be essential. It adds the caveat that "*these studies require special care because the behaviour of storage in the long term depends on it.*" The standard also assumes that most of the data required would not be readily available and that detailed data collection will be needed before the design of the storage facility can begin. Studies required include:

- A general geological survey both at the regional level and on particular points to spot potential structures
- Seismic surveys to determine the structure of the geological layers concerned and, more particularly, to assess the depth and thickness of the reservoir material and of the caprock in connection with wells.
- Exploration drilling – for example testing the caprock for gas tightness.

Security of Storage

A detailed study of the caprock is required to be carried out to prove the existence, and the leak tightness, of the caprock. The study is designed to investigate the hydraulic characteristics of the caprock and in particular, its permeability, in order to determine if faults are present. The standard provides guidelines on what to do if the caprock is found to have discontinuities. To confirm its integrity it requires that a hydraulic test should be performed; also it requires that operating conditions shall be defined which ensure that the gas-filled zone is remote from discontinuities.

In both standards there is a requirement to determine the maximum operating pressure of the caprock so that the following risks are avoided:

- The risk of mechanical failure
- The risk of gas penetration through the caprock
- The risk of uncontrolled lateral spread of the gas

Monitoring

Monitoring requirements in the European Standard for oil and gas fields are limited and call for monitoring of injection and withdrawal rates and material balances and simulation studies to monitor for leakage.

For aquifers the monitoring requirements are considerably more extensive. The Standard calls for monitoring of vertical leakage by gas migration (if any) towards the aquifers located above the reservoir to ensure that leakage remains minimal and acceptable. The system proposed consists of monitoring of upper aquifers and logging wells. Monitoring wells open to aquifers above the storage aquifer shall be designed to enable the detection of gas occurrence, in particular by pressure monitoring. Wells logs (data collected down hole by special survey instruments) are used to monitor the distribution of gas in the storage aquifer, but may also be used to obtain similar information in the upper aquifers. Typically, one logging well is located in the summit zone of the reservoir. Where there are several upper aquifers, one of them can be selected for monitoring because of its spread and its vicinity to the storage to be monitored. This is typically the first continuous aquifer above the one used for storage.

Lateral gas spread is to be monitored using a set of wells. Peripheral monitoring wells will need to be installed in areas that are sensitive to the expected path of gas movement due to structural dips or high permeability pathways. Where the aquifer contains water of drinking quality, or water that is capable of being rendered potable at an acceptable cost, studies are required to determine whether the impact is minimal on water quality in the storage aquifer and connected aquifers. For deep saline formations, there would be a requirement to ensure that there was no contamination of potable water supplies.

7.5 Other EU Framework Projects

It is anticipated that other EU supported projects will also contribute Best Practice experience. These include:

- AZEP
- CARNOT
- CCP
- ECSC
- GASZEP
- GESTCO
- GRACE
- ICBM
- NASCENT
- CO_2STORE
- RECOPOL
- NGCAS

8 COMPILATION OF BEST PRACTICE FROM CASE STUDIES

Best practices for geological storage and transportation of CO_2 are under progress in a wide range of projects - the relevant projects are identified in parentheses in the text below.

Geological Storage

Planning

Detailed characterisation of the reservoir and cap rock is essential, both on a local and regional scale, before injection commences (SACS2) (Weyburn) (CO_2SINK) (Natural gas storage). Prepare a baseline survey of the site (CO_2SINK).

The characterisation should involve a determination of structure and stratigraphy both within and external to the reservoir, together with the physical properties of both the reservoir and cap rock, including identification and mapping of any faults in the reservoir and cap rock (SACS2), seismic surveys will be used to determine the structure of the geological layers (Aquifers used for natural gas storage).

Determine reservoir properties to quantify potential storage capacity and likely migration paths and rates (SACS2), to assess the depth and thickness of the reservoir material and of the caprock (Aquifers used for natural gas storage).

An assessment will be made of the total reservoir storage potential, so that a proper injection strategy with maximum storable volumes can be devised (SACS2), an assessment made of the natural fluid flow in the reservoir (SACS2), and assessment of any possibility of geo-mechanical consequences (SACS2).

Oil and gas fields are preferred because their storage integrity has been proven by hydrocarbon accumulation (Natural gas storage).

Wellbore integrity must be evaluated in detail, allowing for any remedial repair of seal plugs in abandoned wells or other wellbore repairs in active or dormant wells (Weyburn).

Exploration drilling is required with aquifers to test the cap rock for gas tightness amongst other things (Natural gas storage).

A detailed risk assessment must be performed (CO_2SINK).

Obtain the necessary approvals and consent of local authorities and residents – this is expected to take 12-18 months (CO_2SINK).

Obtain approval from regulatory authorities before injection commences; published rules/guidance are helpful (Acid gas injection).

Submission to regulatory authorities will need to include detailed information regarding surface facilities, injection well configurations, characteristics of the injection reservoir or aquifer, and injection operations (Acid gas injection).

Regulatory bodies aim to ensure that plans maximize conservation of hydrocarbon resources, minimize environmental impact and ensure public safety (Acid gas injection).

Regulations framed for acid gas injection should be more stringent than those for CO_2 injection alone but provide a useful benchmark in absence of anything else (Acid gas injection).

More extensive assessment is required for aquifers than for produced oil and gas reservoirs (Natural gas storage).

Design

The accuracy to which the structure needs be resolved depends on the structural form of the reservoir into which the CO_2 is injected (SACS2) – a large dome structure will have different mapping requirements from a reservoir with only minor variations in topography at the upper boundary (SACS2).

Inject into the deepest part of the gas field, furthest from the production well, in order to store CO_2 in the depleting (gas) reservoir (CRUST).

Wells have to be designed to ensure isolation from usable water bearing zones (Acid gas injection).

Choice of location must take account of possible migration pathways (Acid gas injection).

The injection wells must be designed and operated to prevent accidental releases. In acid gas injection operations – injection well design typically consists of a steel string with an outer steel casing cemented to the subsurface formations. Several safety features are incorporated in the injection well to prevent leakage (Acid gas injection).

Safety valves are used down-hole and at well head so that, if something fails, the flow of acid gas from the formation will be prevented (Acid gas injection).

Design of the storage facility includes a detailed evaluation of the reservoir (Natural gas storage), identifying the trapping mechanism, the structure of the reservoir and its closures, identifying any faults and confirming the integrity of all existing and abandoned wells (Natural gas storage).

Site selection

It is essential to have a good understanding of the fluid chemistry and mineralogical composition of any potential reservoir and cap rock so as to elucidate their reactivity with CO_2 (SACS2).

Geochemical investigations will need to be carried out on a site-by-site basis (SACS2).

A baseline of initial conditions of CO_2 flux to the surface should be established by collecting background information prior to injection of CO_2 (Weyburn).

An array of methods should be applied to characterize the underground and understand the in-situ processes (CO_2SINK).

Geophysical surveys should be conducted at the surface and using cross-well methods (CO_2SINK).

A detailed study of the caprock is required to be carried out to prove the existence and the leak tightness of the caprock (Natural gas storage).

A pressure test should be performed on the storage reservoir to establish actual fracture pressure (Natural gas storage). It is necessary to determine the maximum operating pressure of the caprock (Natural gas storage). The bottom hole injection pressure is set no higher than 90% of the fracture pressure to ensure that fracturing of the cap rock does not occur (Acid gas injection).

Operating conditions must ensure that the gas-filled zone is remote from discontinuities in the reservoir cap rock (Natural gas storage).

Setting operating limits is a key feature in the regulatory process to protect the integrity of the injection including maximum well head and bottom hole injection pressures, maximum daily injection rates and maximum injection volumes (Acid gas injection).

Operation

CO_2 need not be dehydrated for injection but the injection temperatures and pressures must be set to ensure that hydrates do not form (SACS2).

Biannual progress reports are given to the regulatory agencies on the licensed operating parameters, well casing integrity and packer tests, etc. (Acid gas injection).

The injection well is pressure tested for integrity once a year (Acid gas injection).

Monitoring

Even with the CO_2 in a supercritical, rather than a gaseous state, CO_2 accumulations can be detected at thickness as low as about one metre under good conditions for collecting seismic data (SACS2).

Other monitoring techniques for offshore application, such as multi-component seismic monitoring, and gravity surveying, have potential benefits but their cost is considered to be a severe drawback for offshore monitoring (SACS2).

Micro-seismicity has potential as a continuous monitoring tool but there are questions about it which need to be resolved (SACS2).

Soil gas sampling and analysis techniques can be used for the monitoring of potential CO_2 leakage in the near-surface (Weyburn).

Systems analysis-based assessment methodology can be used to characterise the long-term fate of CO_2 and storage performance (Weyburn).

Comparison of various software and simulation packages codes build confidence in the results (Weyburn).

Monitoring programmes are required to learn about the injectivity of the field and to detect breakthrough of the re-injected CO_2 (CRUST). Also, sub-surface monitoring of the injected gases would be beneficial to confirm that the gas plume cannot migrate out of the reservoir containment area (Acid gas injection).

Subsurface monitoring is not always required by the regulatory bodies to study whether migration is occurring (Acid gas injection) but whether this experience is relevant to future storage of CO_2 is not clear.

Monitoring of injection and withdrawal rates is required for material balances (natural gas storage) and to enable simulation studies to monitor for leakage (natural gas storage).

In the case of aquifers, additional monitoring is required in the form of monitoring of overlying aquifers (typically the one immediately above the storage formation) and logging wells (typically, one well located in the summit zone of the reservoir) as well as peripheral wells in areas expected to be in the path of gas movement (natural gas storage).

Security of storage

Pre-injection reservoir simulation should be carried out with a reservoir model which is based on the best available geological data (SACS2). Knowledge of the geological setting and characteristics is critical to assess the integrity of the host formation or reservoir, and the short- and long-term fate of the injected gas (Acid gas injection).

A detailed assessment of the regional geology and hydrogeology must be undertaken to select the location of the injection well to minimise leakage (Acid gas injection).

It is particularly important to identify potential migration pathways from the injection zone to other formations, shallow groundwater and/or the surface (Acid gas injection). It is also important to predict and follow the fate of CO_2 over time and evaluate storage stability and integrity (CO_2SINK).

Existing reservoir simulators can be used to model CO_2 migration provided that the physical properties of the CO_2 /brine system are well represented (SACS2).

Future movement of the injected CO_2 plume can be described and predicted by calibrating and “history matching” a reservoir simulation model to the development of the seismic images over time (SACS2).

The information produced can be transferred easily to other locations and allows the effectiveness of the technique and its associated costs to be fully assessed (Weyburn).

Safety

An Emergency Planning Zone (ERP) is required around the injection well in case of an accidental release of acid gas – gas detection and alarm systems, windsocks, self-contained breathing apparatus, and remote unit and plant shutdown stations are needed (Acid gas injection).

Further research is needed on the potential for acid gas to react with the cap rock/well cements and reduce reservoir integrity and identify possible failure modes (Acid gas injection). Also sub-surface monitoring of the injected gases would be beneficial to confirm that the gas plume cannot migrate out of the reservoir containment area (Acid gas injection).

Transmission system

Design and operation

Pipelines transporting acid gases are usually short, typically 100 to 200m, and are constructed of mild steel (Acid gas injection).

Acid gas is dehydrated to avoid corrosion and avoid hydrate formation to prevent compressor breakdown and plugging (Acid gas injection). CO_2 need not be dehydrated for injection but the injection temperatures and pressures must be set to ensure that hydrates do not form (SACS2).

Pipelines are monitored using a supervisory control and data acquisition (SCADA) system (Acid gas injection).

An Emergency Response Plan (ERP) is required for safety management in the event of a leak (Acid gas injection).

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10 ABBREVIATIONS AND ACRONYMS

AEUB	Alberta Energy Utilities Board
C	Carbon (elemental, often used as a shorter term to represent CO_2)
CBL	Cement Bond Long
CIL	Casing Inspection Log
CCP	CO_2 Capture Project (Joint Industry Project between BP, ChevronTexaco, EnCana, ENI, Norsk Hydro Statoil, Shell, Suncor)
CFD	Computational Fluid Dynamics
CCS	Carbon (dioxide) capture and storage
CDM	Clean development mechanism
CHP	Combined heat and power
CIG	Coal integrated gasification
EGR	Enhanced gas recovery
ECBMR	Enhanced coal bed methane recovery
EOR	Enhanced oil recovery
EPA	(United States) Environmental Protection Agency
FEP	Features, Events and Processes
IPCC	Intergovernmental Panel on Climate Change
LCA	Life Cycle Analysis
NGCC	Natural gas combined cycle
NGO	Non-Governmental Organisations
IGCC	Integrated gasification combined cycle
JI	Joint implementation
HHV	Higher Heating Value
LHV	Lower Heating Value
ICC	Integrated combined cycle
IECM	Integrated Environmental Control Model
BIGCC	Biomass integrated gasification combined cycle
GICC	Gas integrated combined cycle
CIGCC	Coal integrated gasification combined cycle
LEM	Lifecycle Emissions Model

RAC	Risk acceptance criteria
RCRA	Resource Conservation and Recovery Act
SACS	Saline aquifer carbon storage
SDWA	Safe Drinking Water Act
SOFC	Solid Oxide Fuel Cell
SPE	Society of Petroleum Engineers
UIC	Underground injection control
USDW	Underground sources of drinking water

11 APPENDIX A: ACKNOWLEDGEMENTS

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12 APPENDIX B: REVISION HISTORY

Revision	Date	By Whom	What
01	March 29, 2004	Flach, Johnsen, Lehmann	1st draft
02	April 10, 2004	Flach	Incorporating comments from A. Cutler and with task assignments
03d	June 1, 2004	Flach	Includes comments and suggestions from the CO2NET2 WP7 meeting in Utrecht
04	December 31, 2004	Paul Feron, Paul Freund, David Hanstock, Erik Lysen	Revised text and insertion of Conclusive Summary section

13 APPENDIX C: NOTICES

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