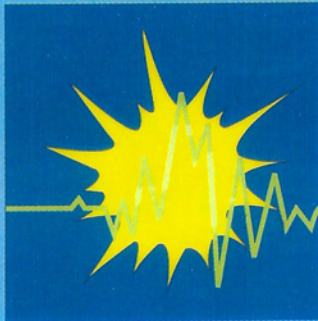


Non-Nuclear Energy
(JOULE) Programme



The Underground
Disposal of CO₂



JOULE II PROJECT NO. CT92-0031
SUMMARY REPORT

**THE UNDERGROUND DISPOSAL OF
CARBON DIOXIDE**



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FOREWORD

This report gives the detailed results, conclusions and recommendations of Joule II project No. CT92-0031: 'The Underground Disposal of Carbon Dioxide'. A summary of the results of the project is given in the Summary

Report of the project, which was compiled on 28 February 1995.

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1 Aims and introduction

It is now generally accepted that man-made CO₂ emissions are contributing to the global rise in atmospheric CO₂ levels (e.g. Houghton, 1994). Rising atmospheric CO₂ levels cause a rise in the radiative heating of the Earth's surface and lower atmosphere — an enhanced greenhouse effect. The possibility that the enhanced greenhouse effect may result in changes in climate, which could on balance be harmful to man and the planet's natural ecosystems, is now causing widespread international concern.

Most man made CO₂ emissions are caused by our use of fossil fuels. At present, the use of fossil fuels is central to the well being of any industrial society and cannot simply be cut off at a stroke. Thus there is an urgent need to research ways in which CO₂ emissions could be abated without drastic alterations to our way of life.

One way of reducing CO₂ emissions without radically altering our use of fossil fuels for power generation could be to dispose of CO₂ from power station flue gases underground rather than emitting it to the atmosphere. The purpose of this study is to determine whether this could be done practically, safely and economically, with minimal long term effects on man or the global environment. The

study focuses on the possibilities for the underground disposal of CO₂ from power plant in Europe, as the necessary detailed information on the geology, power supply and emissions is available for this area. However, its principles are generic rather than area specific, and therefore have global application.

Electricity generation contributes about 30% of global CO₂ emissions from fossil fuel consumption (Thurlow, 1990) and thus about 24% of total global anthropogenic CO₂ emissions. Given the global drive to raise living standards, and the projected rise in the world's population, it is likely that global energy demand will continue to rise for the foreseeable future. Current uncertainties about nuclear power, the low global market share of renewable energy, and the existing power generation infrastructure mean that it is likely that in the next few decades at least, a high proportion of the demand for electricity will be satisfied by fossil fuel fired power generation. Fossil fuel fired thermal power stations are among the largest point sources of CO₂ emissions to the atmosphere and thus form a natural focus for initial studies for CO₂ emissions abatement.

2 The quality and quantity of carbon dioxide that might become available for disposal from fossil fuel fired power plant

2.1 THE COMPOSITION OF UNTREATED OR DESULPHURISED FLUE GAS FROM FOSSIL FUEL FIRED POWER PLANT

Untreated flue gas from conventional power stations contains only about 3–16% CO₂ and is much less compressible than pure CO₂. Typical temperature/pressure conditions for underground storage are likely to be around 35°C and 11 MPa. Compressed flue gas from a coal fired power plant, containing 15% CO₂, would require about 68 m³ storage space per tonne of CO₂ if stored at these conditions. However, if the CO₂ was to be separated from the flue gas and then compressed it would be a supercritical fluid at 35°C and 11 MPa and require about 1.34 m³ storage space per tonne. Therefore roughly 50 times less storage space is required to dispose of pure CO₂ than compressed flue gas. Due to the vast scale of disposal required to make an impact on global emissions of CO₂ to the atmosphere, it is desirable that the available storage space is used economically. Also, it is not desirable to co-dispose of the vast quantities of harmless atmospheric components, principally nitrogen, which make up the bulk of conventional untreated flue gas.

There is also an overriding thermodynamic argument that prohibits the storage of untreated flue gas containing only around 15% CO₂ at these conditions. Due to the large volume of the flue gas, the work needed to compress it would be 65% or more of the total work that could be obtained from the coal fired power plant. This would, at best, make it a far more expensive process than CO₂ separation.

Therefore we conclude that if underground disposal of CO₂ from power plant is to be practised on a scale sufficient to make an impact on global emissions of CO₂ to the atmosphere, the CO₂ would have to be separated from the flue gas before disposal.

2.2 TYPES OF THERMAL POWER PLANT AND APPROPRIATE METHODS OF CO₂ REMOVAL

The vast majority of the world's thermal power plant are coal-fired, pulverised fuel (PF) plants. In modern power stations of this type, the flue gas is passed through a desulphurisation plant (such power stations are known as pulverised fuel plus flue gas desulphurisation, or PF + FGD plant). Flue gas desulphurisation would be a requirement on all power stations involving CO₂ removal. The gas stream for CO₂ removal from PF + FGD plants would be cool, at near atmospheric pressure, and would contain about 15% CO₂. For a PF + FGD plant, the least expensive method of CO₂ separation would be amine scrubbing (Goldthorpe, Cross & Davidson, 1992).

The few existing conventional oil fired plants would probably use amine scrubbing at similar conditions, but at slightly lower concentrations, say 13% CO₂.

In natural gas fired combined cycle (NGCC) plants, gas turbines are used to generate power. Heat from the exhaust of the gas turbines is then used to generate steam which is fed into a steam turbine to produce additional power. The gas stream for CO₂ removal would contain about 3–3.5%

CO₂. Amine scrubbing is the least expensive method of CO₂ removal from such a gas.

As an alternative to separating CO₂ from the flue gas of a conventional power station, in which the fuel is burnt in air, CO₂ could be concentrated by burning fuel in an O₂/recycled CO₂ atmosphere. This would produce a flue gas containing about 85–90% CO₂, with water, small amounts of nitrogen and oxygen, and small amounts of SO₂ and NO_x, depending on the quality of the coal. This process has been evaluated by Argonne National Laboratory in the USA, using a specially converted coal fired boiler (US Department of Energy, 1993). It might be possible to retrofit a PF plant to use this process. Cryogenic separation of the CO₂ from the flue gas to remove impurities would result in around 95% CO₂ recovery.

Integrated gasification combined cycle (IGCC) power plant technology has been demonstrated and is being seriously considered in 21 countries, eight of which have plans to build commercial plant. These plants gasify solid fuel (coal, lignite, etc.) with oxygen at pressure. Part of the power is obtained by burning the resulting fuel gas in a gas turbine and part is obtained from a steam turbine, which uses steam raised from the gasifier and the gas turbine exhaust to produce more power. The standard IGCC process can be modified to remove CO₂ by the addition of a shift unit to convert the carbon monoxide in the fuel gas to carbon dioxide and hydrogen, and adding a CO₂ removal stage, leaving a stream of hydrogen to be burnt in the gas turbine (Goldthorpe et al., 1992). The CO₂ for removal would be at a concentration of about 40% and at high pressure, so physical solvent scrubbing would be a suitable method of CO₂ removal. (Goldthorpe et al., 1992). In the future, membrane technologies may be available to separate CO₂ from hydrogen.

2.3 EMISSION FACTORS FOR FOSSIL FUELS USED TO FIRE THERMAL POWER PLANT

Fuel type has an important bearing on the CO₂ emissions from thermal power plant. This means there are opportunities to save on CO₂ emissions by fuel switching, at least while natural gas is plentiful. Emission factors for the main fuels are shown below:

Brown coal	1.18 kg CO ₂ /kWh
Hard coal	0.97 kg CO ₂ /kWh
Oil	0.85 kg CO ₂ /kWh
Natural gas	0.53 kg CO ₂ /kWh

2.4 COST OF CO₂ RECOVERY

Table 1 shows a comparison of the costs for the least expensive power station/CO₂ separation technology options. These are based on state of the art technology applied to plant generating power at 0.05 Ecu cents/kWh and a reference coal price of 2.21 Ecu/GJ.

Studies have indicated that the cost of removal and disposal of CO₂ from power plants is dominated by the

Table 1 Evaluation of preferred combinations of power plant and CO₂ separation methods.

CO ₂ abatement process	Nominal CO ₂ recovery (%)	Cost of electricity without CO ₂ removal (ECU cents/kWh)	Cost of electricity with CO ₂ removal (ECU cents/kWh)	Cost of CO ₂ emission avoidance (ECU/tonne)
PF + FGD + Amine scrubbing	90	5	9.4	57
IGCC + Physical Absorption	90	5	7	27
NGCC + Amine scrubbing	90	5	7.3	64
Oxygen/CO ₂ recycle	98	Not applicable	8.6	42*

* This figure is calculated in comparison to a PF+FGD power plant.

cost of additional equipment and the loss in power output at the power station, provided the CO₂ disposal location is not too far from the power plant.

By comparison, the current cost of electricity generated by wind turbines is around 7-8 Ecu cents/kWh and the cost of electricity from nuclear power stations (including decommissioning) is estimated to be even higher.

2.5 QUALITY OF CO₂ WHICH MAY BECOME AVAILABLE FOR DISPOSAL WHEN SEPARATED FROM POWER PLANT FLUE GASES

The trace contaminants from CO₂ separated from an oxidising gas, such as flue gas from a PF+FGD power plant, differ slightly from those which could be separated from a reducing gas, such as a shifted synthesis gas derived from an IGCC plant. However, in both cases 99% pure CO₂ could be produced and dried to meet disposal requirements which would prevent corrosion of the transport and disposal system.

2.6 QUANTITY OF CO₂ WHICH MAY BECOME AVAILABLE FOR DISPOSAL

The quantities of CO₂ likely to be emitted by the various types of power plant considered in this study are shown below. The specific values of emissions are very sensitive to the thermal efficiency of the modified plant, which is not precisely known at present.

Table 2. Likely emissions in tonnes of CO₂ for 500 MW (e) power plant fitted with CO₂ separation.

Plant type	Emission/hr	Emission/year	25 yrs
PF + FGD	600	4.47 Mt	112 Mt
IGCC	500	3.72 Mt	93 Mt
NGCC	257	1.91 Mt	48 Mt
O ₂ /CO ₂ recycle	660	4.91 Mt	123 Mt

2.7 1990 CO₂ EMISSIONS FROM THERMAL POWER GENERATION IN THE EU AND NORWAY

The quantity of CO₂ produced by thermal power generation in the European Union and Norway in 1990 is shown in Table 3.

The total represents 31.2% of EU energy related emissions. If CO₂ separation were to be implemented to reduce the total CO₂ emissions from power production, then for each tonne of CO₂ emission avoided about 1.5 tonnes of CO₂ would have to be disposed of, because of the reduction in power plant efficiency caused by the separation process

2.8 FUTURE CO₂ EMISSIONS IN THE EU AND NORWAY

In the medium term (10 years) these emissions are unlikely to increase significantly. They are constrained by EU and Norwegian obligations under the Rio Framework Convention on Climate Change and committed investment in power plant.

Predictions of long-term future CO₂ emission levels contain a high degree of uncertainty because of the influence of political and sociological factors on the energy market — for example the possible implementation of an EU energy/carbon tax, continuing uncertainty over the future of nuclear power, or the prospect of government intervention in the energy market for domestic reasons (e.g. through support of indigenous coal industries).

Table 3 CO₂ emissions from thermal power generation in 1990.

Country	Electricity Production TWh	Thermal Power Production TWh	CO ₂ Emissions Mt CO ₂ (1990)
Belgium	70.85	27.21	24.6
Denmark	25.75	25.08	23.0
France	420.16	48.14	44.4
Germany	449.49	283.92	340.6
Greece	35.00	33.00	35.8
Ireland	14.52	13.53	11.0
Italy	216.89	181.78	122.7
Luxembourg	1.38	0.56	1.5
Netherlands	71.87	68.19	45.8
Norway	106.00	—	0.1
Portugal	28.50	19.20	15.2
Spain	150.62	70.17	64.4
United Kingdom	318.99	246.13	220.9
TOTAL	1803.99	1016.91	950.6*

* = 0.95 Gt CO₂.



3 CO₂ transport

The most practical way to transport large and continuously supplied volumes of CO₂ to a disposal site is by pipeline. Following separation at the power plant, the CO₂ is likely to be compressed to around 10 MPa at 10°C for transport as a liquid.

3.1 PIPELINE SPECIFICATIONS

Long distance high pressure liquid CO₂ pipelines are currently in use in the Enhanced Oil Recovery (EOR) industry in the USA. The longest existing CO₂ pipeline is the 656 km Sheep Mountain pipeline. It carries CO₂ from southern Colorado to the Permian Basin in Texas. It is in two segments with diameters of 500 and 610 mm.

The required specifications for transport of liquid CO₂ at 10°C and 10 MPa are a carbon steel pipe with:

- High impact toughness to resist crack propagation.
- The ability to withstand low temperature conditions down to -20°C in normal operation.
- The ability to withstand rapid temperature change caused by line depressurisation which could cause the temperature to fall as low as -78.5°C, which is the solid sublimation temperature at atmospheric pressure.
- Resistance to corrosion from mild carbonic acid which may result from the inclusion of small quantities of water in the CO₂ supplied from the power plant.

These specifications are met by impact tested API 5L carbon steel. The pipeline would be of fully welded construction with an external cold tar wrap for corrosion protection. It would normally be buried to a depth of 1 m, but would be deeper where necessary.

3.2 CO₂ PIPELINE COSTS

The costs of pipeline construction are principally dependent on the length of the pipeline and are likely to be about 1 to 2 million Ecu per kilometre, depending on the diameter, for a mild steel construction. Since large pipes have much greater carrying capacity, single large pipe installations would be cheaper than multiple small pipe systems. The largest feasible size of a CO₂ disposal pipeline would be about 1 m diameter. Such a pipe would have a carrying capacity of about 2500 tonnes per hour of CO₂.

The cost of subsea pipelaying may typically be about the same as land based pipelaying. The technology for laying pipes in deep water is developing and depths of about 1000 m have been achieved.

If the possibility of a pipeline rupture was identified as unacceptable for a specific application then the cost of the pipeline would increase dramatically because of the need for an alternative design such as double walled construction.

Once constructed, the costs of operation and maintenance of the pipeline are trivial compared to the other costs of the CO₂ abatement system.



4 Concepts of underground disposal

4.1 SHALLOW DISPOSAL AS A GAS

Theoretically, CO₂ could be stored underground at shallow depths as a gas. However, the amounts of CO₂ which would have to be disposed of to make an impact on the amounts emitted to the atmosphere are far greater than could be accommodated in existing gas-tight man made voids. Most aquifers at shallow depths are already used, for potable water supply, so they would not be available for bulk CO₂ storage. So there is not enough space available for storage of CO₂ as a gas at shallow depths to make a significant impact on global CO₂ emissions.

4.2 SHALLOW DISPOSAL AS A LIQUID

At depths shallower than about 700 m below the surface, where the temperature is below the critical temperature of CO₂ (31.1°C), it might be possible to store CO₂ as a liquid. However, under normal subsurface conditions, it would be necessary to overpressure the host formation to produce liquid CO₂. If overpressure was to be maintained in the medium term it would require a completely sealed host formation. This effectively rules out most shallow sedimentary rock reservoirs. Overpressuring of man made voids might be possible, but geotechnical problems, such as fracturing of the host rock, might occur. The most suitable voids might be in evaporite deposits, for example, salt caverns originating from solution mining of salt. However, apart from their relatively small size, these are full of brine, which would have to be used or disposed of. New man made voids would be prohibitively expensive to engineer. Thus the bulk underground disposal of CO₂ as a liquid is considered impractical.

4.3 DEEP DISPOSAL AS A SUPERCRITICAL FLUID

At realistic subsurface conditions for European sedimentary basins, i.e. a geothermal gradient of 25–35°C/km and a pressure gradient of 10.5 MPa/km, free CO₂ would be in the supercritical phase at depths of about 800 m or more below ground. Its density would vary between about 440 and 740 kg/m³. Thus it could be stored in a relatively dense phase in porous and permeable reservoir rocks without the need for special pressure conditions. This is critically important, as there would be a vast increase in the space available for storage compared to disposal at shallow depths. Most reservoirs at depths of 800 m or more are unused or used only for the exploitation of geothermal or hydrocarbon resources.

Under the pressure/temperature conditions prevailing underground, free CO₂ is less dense than water. So deep underground storage requires a seal above the underground reservoir which would prevent the CO₂ migrating, under its own buoyancy, back to the surface of the Earth, at least in the medium term (thousands of years). This would normally be a clay, shale or other rock which would be impermeable to CO₂ within this time frame. The CO₂ would also

need to be confined laterally within the reservoir. One way to achieve this would be to confine the CO₂ within a depleted hydrocarbon field, or a fluid trap in an aquifer directly analogous to a hydrocarbon field. However, other possibilities exist:

Gunter et al. (1993) have suggested that CO₂ could be injected into reservoir rocks in large sedimentary basins and trapped there without the need for a lateral seal. The CO₂ could be injected into the host formation — ideally a thick immature sandstone — in an area where it would move very slowly along a long flowpath at approximately the speed of the natural groundwater flow. As it moved through the reservoir, both vertically and laterally, it would come into contact with uncarbonated formation water and reactive minerals. A proportion of the CO₂ would dissolve in the formation water, and some of this dissolved CO₂ would become permanently fixed by reactions with minerals in the host rock. If the flowpath was long enough, the CO₂ might all dissolve or become fixed by mineral reactions before it reached the basin margin. Thus it would be trapped in the reservoir. Such possibilities would bring those parts of deep reservoirs outside the conventional geological traps into play. This would vastly increase the storage space available for CO₂ deposition.

These two concepts; disposal into conventional geological traps and disposal without the need for conventional traps, are both entirely valid methods of disposal. They are considered in more detail below.

4.4 DISPOSAL INTO CONVENTIONAL GEOLOGICAL TRAPS

For the purposes of CO₂ disposal, conventional geological traps fall naturally into three categories; gas fields, oil fields and traps on reservoirs containing no hydrocarbons, referred to here as aquifers. The advantages of disposal into a disused hydrocarbon field include the proven trap of known volume and the fact that the geology is well known from the field development. However, if the original wells used in the field development were poorly plugged, they could cause the trap to leak. Such wells can be very difficult to seal.

4.4.1 Disposal in gas fields

When a gas (methane) field is exploited, the gas is usually under hydrostatic or greater pressure. Methane has a low viscosity and can commonly pass freely through the interconnected pore spaces within even a relatively low permeability reservoir rock. When a production well is opened, the gas expands and is usually allowed to flow naturally to the well without any form of artificial stimulation, gradually depleting the pressure differential between the surface and the reservoir. When production ceases, a high proportion (up to 95%) of the gas will have been extracted. Unless the permeability of the reservoir is high, not much formation water is likely to invade the field (because the formation water is much more viscous than the gas) and the reservoir pressure will be much lower than

before production, the pore space being occupied largely by very low pressure methane. For example, the Indefatigable gas field in the North Sea derives most of its depletion energy from expansion of the gas in the reservoir. Less than 2% of the energy comes from water drive and compression of the reservoir matrix (Pearson, Young & Smith, 1991). So, if 95% of the gas in place is produced, and 2% of the volume originally occupied by the gas is occupied by water or by compression of the rock matrix, about 93% of the volume of the field might theoretically be available for CO₂ storage. Recoverable reserves are commonly conservative compared to eventual production. So, if CO₂ disposal was started soon after field abandonment, we believe that approximately 100% of the space originally filled by the estimated recoverable gas reserves could be occupied by CO₂ before the original reservoir pressure is reached. This is because the CO₂ can move freely through the interconnected porosity of the reservoir, compress the remaining methane and occupy nearly all the non-water-filled pore space. However, over time the storage capacity of depleted gas fields will be gradually eroded by water invasion.

When CO₂ is mixed with small amounts of methane its density is reduced. However, in most cases, this will reduce the amount of CO₂ which can be stored at a given temperature and pressure in a gas field by less than 3%.

4.4.2 Disposal in oil fields

When an oil field ceases production it is because the field has become uneconomic, not because all the oil has been produced. Typically, about 30% of the oil initially in place may be recovered in primary production, i.e. by simply opening up the wells and allowing the oil to flow to the surface, or by pumping it to the surface. Even in fields in which secondary recovery by waterflooding (injecting water into the reservoir below the oil to displace the oil and increase the pressure in the reservoir) has taken place, around 50% of the oil initially in place may remain within the reservoir, and further (tertiary) production, often achieved by injecting CO₂ into the reservoir, is likely to start if perceived as economic. As CO₂ is such a good fluid for use in enhanced oil recovery (EOR) operations, it is unlikely that any oil field owner would allow CO₂ disposal without EOR or appropriate financial compensation. Our economic analyses show that if cost credits from the sale of recovered oil are considered, but the extra CO₂ generated by burning this oil is not considered, the cost per tonne of CO₂ avoided by disposing of CO₂ in oilfields with EOR could be almost zero.

As fluid production has taken place in depleted oil fields, the pressure is likely to be substantially reduced compared to the original reservoir pressure. Also, further production of oil and formation water will occur during CO₂ injection for EOR operations. This will greatly increase the space available for CO₂ deposition. The amount of CO₂ stored in such projects will depend greatly on the aims of the project; whether it is entirely for EOR or for EOR and CO₂ deposition or whether it is to maximise CO₂ deposition. It will also depend on whether CO₂ injection begins at the start of field development or towards its end, and also of course on the reservoir specific parameters. Reservoir simulations suggest that, as a simple rule, in a tertiary CO₂ injection project aimed both at enhanced oil recovery and CO₂ storage, the total storage potential for CO₂ is a volume equivalent to all a field's secondary and tertiary recoverable reserves. For the

purposes of storage capacity estimates we have taken the view that the total CO₂ storage capacity is equivalent to the estimated recoverable reserves of the field. This is partly for the practical reason that the recoverable reserves of most fields are publically available, whereas estimates of secondary and tertiary recoverable reserves are either unknown or not in the public domain.

4.4.3 Disposal in traps on aquifers

Two advantages of aquifer disposal are: Traps on aquifers are more common than oil and gas fields, and there may be some very large traps on aquifers available for CO₂ storage.

Pressure considerations

Unlike oil and gas fields, where the reservoir pressure has been very substantially lowered by production of the reservoir fluids, the reservoir pressure in aquifers is hydrostatic or greater. This has far reaching implications for the amount of CO₂ which can be stored in them. When CO₂, or any other substance, is injected into a reservoir rock whose pore spaces are filled with water, there will be an increase in pressure around the injection well. The level of pressure buildup and the speed of the subsequent re-equilibration will depend on the injection rate, the permeability and volume of the reservoir, and the permeability of the reservoir margins. Two end members for the potential aquifer system can be envisaged; one — an open aquifer — in which the reservoir groundwater is in uninterrupted continuity with the ground surface or sea bed, and another — a closed aquifer — in which the aquifer groundwater is fully sealed from other aquifers, the ground surface, or sea bed by permeability barriers such as faults or shales. In practice, most aquifers will fall between these end members, being tortuously connected to the surface or sea bed through a number of partial permeability barriers. Open aquifer systems are hydrostatically pressured, whereas closed systems, or almost closed systems, may be hydrostatically pressured or overpressured.

A closed system is, by definition, a trap for fluids. When fluid is injected into a closed system — assuming the margins of the system do not rupture — the only space available for the injection of the CO₂ is that created by the compression of the rock matrix and groundwater. In North Sea subsurface conditions it is estimated that a volume of CO₂ equivalent to only around 2% of the pore volume of the closed system would increase its pressure by approximately 10 MPa. In closed but normally pressured aquifer systems an increase in reservoir pressure of 10 MPa could be acceptable, allowing a volume of CO₂ equivalent to around 2% of the pore volume to be injected. It is likely that many hydrostatically pressured older reservoirs, such as the Permo-Triassic reservoirs of the Southern North Sea, may be sufficiently divided by faults and other permeability barriers that they approximate to closed systems. Speculatively, this could explain why there is such low water influx into the Indefatigable gas field. However, for the majority of European reservoirs, we simply do not know whether they approximate to open or closed aquifer systems.

The deeper parts of many Northern and Central North Sea reservoirs are aquifer systems which can be regarded as closed, at least in the medium term, as they are naturally overpressured. For example, the pre-Cretaceous reservoirs of the North Sea Grabens are generally overpressured and, in the centre of the Grabens, highly overpressured (Buhrig,

1989; Gaarenstroom et al., 1992). Pressure measurements taken in these reservoirs indicate that they are divided into compartments, probably by faults (Buhrig, 1989). Each compartment could be considered as a separate trap. In many wells drilled into these reservoirs, the difference between the fluid pressure in the reservoir and the fracture pressure of the overlying sealing formation is low. Bearing in mind that the well is not necessarily drilled at the point where the seal is weakest, the implication is that the pore fluid in the compartments may be at, or very close to, the fracture pressure of the seals. So the amount of CO₂ which could be injected without rupturing the seal could be very small. In practice it would commonly be unsafe to inject CO₂ into such overpressured formations because injection would produce a large pressure buildup around the injection well during injection, and thus a likely place for the seal to rupture would be around the injection well. Thus overpressured reservoirs are unlikely to be a first choice for CO₂ disposal.

Displacement of formation water in open systems

When CO₂ is injected into an open aquifer system there will be a transient pressure increase around the well, which will be larger in low permeability rocks. This will decline as pressure equilibrates throughout the reservoir and, theoretically, could eventually return to the initial pressure, as the CO₂ will displace (saline) groundwater, which will migrate towards the ground surface or sea bed. Offshore, this will eventually result in the displacement of marginal formation water onto the sea bed. This might not be significant ecologically, as the salinity of the formation water near the sea bed differs little from that of seawater. Onshore it might cause a perturbation in the saline/fresh water interface (which could cause a rise in the salinity of water at abstraction wells), or a rise in the water table.

Permeability requirement

If, during injection, the reservoir pressure is allowed to exceed the fracture pressure of the solid matrix of the reservoir rock, the rock matrix will fracture. The CO₂ will move preferentially along the fractures, bypassing the pore spaces. This will reduce the storage efficiency of the reservoir. It will also create new migration pathways if the fractures propagate into the sealing formation or into parts of the reservoir outside the trap. High permeability in the host reservoir will be required around the injection wells, to cope with the high injection rates needed for CO₂ disposal, even in a completely open aquifer. As the pressure will decline radially from the injection point, high permeability would not be necessary at long distances from the injection site. In practice however, there are few reservoirs with low average permeability which have readily identifiable areas of high permeability which could be used as injection sites. The rate of injection needed for a CO₂ disposal project based on a single 500 MW PF + FGD power station, would be slightly less than 15 000 tonnes/day. The number of wells which might be required to inject this amount of CO₂ would be reservoir specific and dependent on the reservoir characteristics. As an example, Van der Meer (1992) suggested that in a realistic Dutch subsurface aquifer disposal scheme, this volume of CO₂ could be handled by 6 wells injecting 2500 tonnes/day into the reservoir. Given that fracturing of the rock matrix is undesirable, a minimum average permeability of 100 millidarcies in the disposal reservoir would probably be required to cope with these injection rates. Of course, the

lower the injection rate per well, the lower the permeability requirement.

Dissolution of CO₂ into the formation water

If CO₂ was to be stored in a closure on an aquifer, there would be some dissolution of CO₂ into the formation water during injection. The amount of dissolution would depend mainly on the temperature, pressure and salinity of the formation water and the efficiency of mixing at the CO₂/water interface. Following injection, there would be some slow diffusion of CO₂ into the formation water in a thin skin around the CO₂ 'bubble'. This would probably not be significant in time frames of a few thousand years unless there was significant groundwater flow, exposing water undersaturated with respect to CO₂ to the pool of free CO₂. There is slow but significant groundwater movement in many deep aquifers. If CO₂ were to be stored in a closure on such an aquifer, there would be gradual dissolution of CO₂ at the CO₂/water interface. In the very long term this could remove all the CO₂ from its confining trap.

The displacement process

CO₂ is more buoyant and much less viscous than formation water. When CO₂ is injected into a trap on an aquifer, it will enter the pore spaces almost entirely by displacing the formation water. However, a small proportion of the CO₂ will dissolve in the formation water, which may cause it to react with carbonate and basic aluminosilicate minerals within the rock framework.

The CO₂ displaces the formation water in the pore spaces inefficiently. It migrates preferentially along lines of higher permeability within the inhomogeneous reservoir rock, bypassing much of the pore space. Reservoir modelling and experience from enhanced oil recovery operations indicate that it will rise rapidly to the top of the trap and then migrate laterally in a series of 'viscous fingers' along the roof of the trap to the trap margins (or spill points). Thus when CO₂ begins to spill from the trap into the untrapped part of the reservoir, only a low percentage of the available pore space within the trap will be occupied by CO₂. This figure (the storage efficiency of the trap) can be modelled using reservoir simulators. It is highly case specific. In most realistic injection scenarios it lies between 1 and 6% and modelling suggests it is likely to average close to 2%. Storage capacity estimates are highly sensitive to storage efficiency. Simulations made specifically for this study have been published by van der Meer (1994) and Holt, Jensen & Lindeberg (1994) and Lindeberg (1995).

Size of suitable geological traps on aquifers

Given the investment necessary to separate the CO₂, and the requirement to make an impact on total emissions, it is likely that the minimum quantity of CO₂ that would be sent for disposal would be equivalent to the lifetime emissions from a single 500 MW(e) PF+FGD power station, i.e. about 0.12 gigatonnes CO₂. An effective pore volume of approximately 0.18 km³ (assuming a supercritical CO₂ density of 0.7 kg/m³) would be needed to store this CO₂. For aquifer storage, given a realistic effective porosity of 30% and a storage efficiency of 2%, this represents a rock volume of about 30 km³. This can be visualised as a circular trap with a diameter of about 19.5 km on a reservoir 100 m thick.

For much of Europe, seismically derived maps of reservoirs, which are the best way of identifying traps, are proprietary and confidential, as the seismic data have been

acquired at great expense by oil companies. On the basis of the data we have been able to obtain for onshore Europe, a few traps, or closely associated groups of traps, as large as this have been identified, but they do not appear to be common. This means that significant onshore disposal in traps may be impossible in many European countries, given the assumptions made above. Clearly, increasing the storage efficiency or increasing the number of traps used (and thus costs) are the only practical possibilities for decreasing the trap size requirement.

4.5 DISPOSAL WITHOUT THE NEED FOR A CONVENTIONAL TRAP

4.5.1 Disposal offshore without a conventional trap

Offshore, CO₂ disposal into reservoirs which do not have lateral seals (using the concept of Gunter et al, 1993, outlined above) is thought to be practical. If the reservoirs are chosen correctly, there is no realistic chance of the CO₂ outgassing on land. Furthermore, we do not fear outgassing of methane from the North Sea reservoirs at the sea bed or on land.

In the North Sea there are some very large, very thick aquifers which dip at such a shallow angle that they are essentially horizontal over large areas. These appear highly suitable for this disposal concept. From the simulation point of view, these aquifers are so large and permeable that they can be regarded as essentially infinite. The rate of lateral groundwater flow in many such offshore aquifers might be essentially negligible. Thus once the pressure within the CO₂ 'bubble' injected into the reservoir has equilibrated with the pressure in the formation water, the only force acting on the CO₂ which might cause it to move towards the basin margin would be its relatively high buoyancy compared to the formation water. This could be a very slow process and would be offset by the dissolution of CO₂ into the formation water. Once the CO₂ was dissolved, the forces tending to move it towards the basin margins might be essentially negligible.

In work conducted for this study, Lindeberg (1995) simulated injection into a large but finite aquifer 160 m thick. CO₂ was injected 8000 m from the boundary of the aquifer at a rate of 15 000 tonnes/day for 25 years. The simulation showed that after the injection period the CO₂ would migrate slowly towards the edge of the aquifer, but at the same time there would be a slow vertical diffusional and convective transport of CO₂ taking it into solution in the formation water. When injection ceased, the edge of the CO₂ bubble was only 3000–4000 m from the boundary of the aquifer. It was assumed that the CO₂ reaching the aquifer boundary would escape from the reservoir, and the competing horizontal migration and vertical transport of the CO₂ into the formation brine would determine how much and how fast CO₂ would escape. The escape profiles are highly dependent on the permeability. At permeabilities below 1000 millidarcies (mD) the CO₂ did not reach the edge of the aquifer for more than 1000 years. Furthermore, very little CO₂ was lost because most of the CO₂ dissolved in the aquifer during this period. Using typical simulation assumptions with 250 mD horizontal permeability, the CO₂

never reached the boundary (i.e. it migrated less than 4 km before completely dissolving). The reservoirs in the centre of the North Sea are, in places, more than 200 km from shore. Thus simulation suggests that injection could be so far from shore that there would be no practical likelihood of CO₂ migrating onshore or to the sea bed and affecting man, the marine environment or the surface terrestrial environment. Such offshore reservoirs therefore represent a very large potential sink for CO₂.

Given that it would not be practical to displace more than a small proportion of the formation water with CO₂, we have taken a figure of 6% occupancy when calculating the volumes of CO₂ which could be sequestered into suitable offshore reservoirs.

4.5.2 Disposal onshore without a conventional trap

The same principles apply to the onshore area as the offshore area. But we believe that it is less likely that CO₂ storage would be permitted onshore in Europe unless the CO₂ was confined within a conventional geological trap. Firstly, there may be a legal requirement in some countries that substances disposed of underground have to be recoverable. Secondly, if free CO₂ is able to migrate to depths above about 800 m below ground, it will undergo a rapid decrease in density and accompanying volumetric expansion as it moves from the supercritical fluid phase into the gaseous phase. The prospect of degassing at outcrop has obvious implications for man and the environment. Most otherwise suitable aquifers in onshore Europe outcrop on land at some point and are used for potable water supply, so some kind of trap might be necessary to prove that potable waters could not be affected by CO₂.

4.6 PLANNED UNDERGROUND DISPOSAL SCHEMES

Statoil are to begin the underground disposal of CO₂ from the Sleipner Vest field into the Utsira Formation in 1996. The Sleipner Vest field is a natural gas/condensate field located in the middle of the North Sea, in the Norwegian sector, some 250 km from land. The natural gas contains up to 9.5% CO₂, which means that CO₂ removal is required in order to comply with sales gas specifications of a maximum of 2.5% CO₂. The capture of the CO₂ from high pressure natural gas will be by amine scrubbing. One million tonnes annually of CO₂ will be injected via a single well into a trap on the Utsira Formation for the lifetime of the field. The Utsira Formation is a highly porous and permeable sandstone reservoir 250 m thick and at a depth of 800 m below the sea bed.

A second, similar scheme, to exploit the natural gas fields of the Natuna Sea in Indonesia, is in the planning stage, following agreement between Exxon and Pertamina. The CO₂ and other gases found with the methane in these fields comprise up to 70% of the produced gas. These will be removed and 6 Gt CO₂ will be disposed of in aquifers some 900 m below the sea bed over a 17 year period. This is equivalent to about 6 years of total European CO₂ emissions from power production.

5 Inventory of underground storage capacity for CO₂ in Europe

5.1 INTRODUCTION

For the reasons outlined in Section 4 above, the CO₂ storage capacity of any reservoir, be it a gas field, oil field or aquifer, is highly case specific. Detailed investigation, including reservoir simulation, is required to accurately estimate it. This would be impossible for all the reservoirs in the EU and Norway as not enough is known about most of the aquifers. So in order to make a standardised inventory of the total CO₂ storage capacity of the EU and Norway a number of simplifying assumptions and constraints are essential:

For Aquifers:

1. The reservoir should be sealed by a low permeability cap rock
2. The reservoir should have an average permeability of around 100 mD or more, to allow the injection of large quantities of CO₂ from a small number of wells
3. The reservoir should be 800 m or more below the surface, so that the CO₂ will be in a dense phase
4. Unless known otherwise, the storage efficiency of the aquifer is assumed to be 6% in aquifers which are in open communication with the ground surface, and 2% in aquifers which are closed (commonly, but not in every case, identified by overpressure). A storage efficiency of 4% will be used where it is not known whether the reservoir is open or closed
5. Unless known otherwise, the density of CO₂ at reservoir conditions is assumed to be 700 kg/m³
6. Highly overpressured reservoirs are excluded from the inventory totals

For Gas Fields:

1. The volume of the initially recoverable reserves is available for storage of CO₂
2. Unless known, the gas expansion factor of the gas field is assumed to be 200
3. Fields with less than 10 Mt storage capacity are too small for CO₂ disposal

For Oil fields:

1. The volume of the initially recoverable reserves can be replaced by CO₂
2. Unless known, the Formation Volume Factor is 1.2
3. Fields with less than 10 Mt storage capacity are too small for CO₂ disposal.

Table 4 shows the theoretical underground storage capacity of Europe.

Thus a realistic estimate is that at least 700 Gt CO₂ could be sequestered in the underground reservoirs of Europe. A more conservative estimate of the total storage capacity in Europe is 63.29 Gt. This only includes storage of CO₂ in conventional fluid traps such as hydrocarbon fields or directly analogous traps on aquifers.

Although these are the most tightly constrained figures available to date, it should be re-emphasised that the storage capacity data contain major unknowns, uncertainties and assumptions. The most important of these relate to: a) areas with little or no data on deep subsurface aquifers, b) the volume of closure on the aquifers of Europe, c) uncertainties about the amount of dissolution of CO₂ into water and CO₂/water rock reactions that will occur, and d) our definition of what is a suitable reservoir for CO₂ disposal. We believe that additional information, particularly the details of aquifers in largely unexplored offshore areas, is likely to increase rather than decrease the total potential storage capacity. For example the figures quoted above do not include any estimate of the storage capacity in UK waters West of Shetland, Irish waters west of Ireland or Norwegian waters north of 62°N.

From a European standpoint, the key finding that emerges from this survey is that most of the European storage capacity is offshore, and most of that is in the North Sea. On these grounds alone, the cost and feasibility of offshore disposal in the North Sea should be a focus of future work for European CO₂ disposal.

5.2 AVAILABILITY OF NORTH SEA OIL AND GAS FIELDS FOR CO₂ STORAGE

It is assumed that North Sea gas fields will be available for CO₂ storage when production ceases, as there is little to be gained by CO₂ flooding gas reservoirs. It is assumed here that North Sea oil fields, and fields which contain both oil and gas, will not be used for CO₂ storage except in combination with enhanced oil recovery. It is already clear that the majority of these fields could not be CO₂ flooded until after they have reached the end of their planned productive life. Thus it seems reasonable to assume that they will be available for CO₂ storage at their projected abandonment dates. Details of the cumulative volumes of storage space which will be available year by year in the hydrocarbon fields of the Norwegian and UK sectors of the North Sea are given in Chapter 4 of the main text.

5.3 COMPARISON OF CO₂ EMISSIONS FROM THERMAL POWER PLANT AND CO₂ STORAGE CAPACITY

Table 4 shows that offshore hydrocarbon fields alone have very significant storage potential (about 20 years of current European emissions from thermal power generation). Offshore aquifers may have vast potential (about 700 years of European emissions from thermal power generation). Onshore hydrocarbon fields have insignificant volumes compared to the amounts of CO₂ produced by power plant. Onshore aquifers have significant storage capacities, but many have other uses apart from CO₂ storage, e.g. water supply, so storage would most probably be confined to traps in many areas.

Table 4 Underground storage capacity for CO₂ in Europe (all figures are × 10⁹ tonnes).

Country	Aquifer*		Oil fields		Gas fields	
	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Belgium	0.00	0.00	0.00	0.00	0.00	0.00
Denmark	47	?	0.00	0.13	0.00	0.46
France	3	?	0.05	0.00	0.88	0.00
Germany	2	?	0.06	0.00	2.34	0.00
Greece	?	?	0.00	0.01	0.00	0.02
Ireland	0.00	?	0.00	0.00	0.00	0.16
Italy	0.00	0.00	0.04	0.07	0.85	0.84
Luxembourg	0.00	0.00	0.00	0.00	0.00	0.00
Netherlands	5	?	0.03	0.00	8.46	0.82
Norway	0.00	476	0.00	3.10	0.00	7.19
Portugal	0.00	?	0.00	0.00	0.00	0.00
Spain	?	?	0.00	0.01	0.00	0.04
United Kingdom	0	240	0.04	2.62	0.00	4.88
Totals	57	716	0.22	5.94	12.54	14.40
Sum Total	806.1 Gigatonnes carbon dioxide					

* The figures quoted above are for storage of CO₂ in aquifers without the need for conventional fluid traps. They should be regarded highly provisional. The most conservative estimate for the storage capacity of aquifers would be for storage in conventional traps alone. The totals for this type of storage are 19.51 Gt offshore and 10.67 Gt onshore respectively.

6 The safety and stability of the underground storage of CO₂

6.1 INTRODUCTION

The basic concept of CO₂ disposal underground is to use what is at present a largely unused resource — the pore space existing in deep underground reservoirs — to lessen the perceived environmental damage caused by continuing to add CO₂ to the atmosphere. So, if underground disposal is to become a reality, less environmental damage must be caused, or risked, by disposing of the CO₂ underground. Thus the stability of an underground storage reservoir is fundamental for underground CO₂ disposal and the safety aspects of the transport and injection activity are equally important for its social acceptance.

When considering the risks of disposing of carbon dioxide underground, it is important to remember that in enhanced oil recovery operations in North America, the transport of pressurised liquid CO₂ by pipeline for distances of hundreds of kilometres is routine. Similarly, the injection of substantial quantities of CO₂ into the ground is an everyday occurrence in the oilfields of West Texas and elsewhere. We are not aware that any major adverse environmental effects have been reported from these operations to date. Thus the transport and injection systems for underground disposal of CO₂ are already in use and the risks are deemed acceptable, at least on the present scale of operations.

Many very large natural accumulations of carbon dioxide exist underground. Some of these are exploited commercially for EOR. The gas is found in the pore spaces of sedimentary rocks in exactly the same way as in natural gas (methane) fields. Thus they are close analogues for man made underground CO₂ storage fields. In the USA, geological studies suggest that the CO₂ stored in natural structures in the Jackson Dome area was generated in late Cretaceous times, i.e. around 65 million years ago. If this is true, it appears beyond doubt that the very long term stable storage of CO₂ underground can be achieved. This assertion is supported by the fact that at least two major commercial underground CO₂ disposal projects have now been proposed, see section 3.4.7 above. The purpose of both these schemes is to prevent CO₂ emissions to the atmosphere.

6.2 AVAILABLE DATA

The published research on the effects of subsurface injection of CO₂ is largely focused on the oil-CO₂ interaction and the volumes of CO₂ involved are much smaller than in a CO₂ disposal venture. In the case of Enhanced Oil Recovery (EOR), the idea is to inject a minimum of CO₂ to recover a maximum of oil. So, conceptually, there is a large difference between the operation of a CO₂ storage project and CO₂ injection for EOR purposes. In the past, CO₂ injection into the subsurface by the oil industry has not attracted the attention of environmentalists or governmental control. As a result no relevant data are available in the EOR industry that relate to reservoir stability. The situation is different in the case of the surface and the injection system installation. Since the first production of hydrocarbons, wells have been drilled, and pipelines have been used to transport the product from the pro-

duction location to the market. A wealth of data is available on operating experience with such installations, on the failure rate of all equipment used, and the impact on the environment in case of failure.

6.3 POTENTIAL ADVERSE EFFECTS

Underground CO₂ storage can be considered as a special kind of deep well injection of fluid waste. The benefits of subsurface injection are that it will generally be an economic way to dispose of large quantities of fluid waste and that this waste is effectively removed from the earth's surface. Potential adverse effects are (after Walker & Cox, 1976):

- *Contamination of (potential) natural resources*, e.g. hydrocarbon and groundwater reserves. An additional problem is the assessment of long term effects and limited controllability.
- *Pre-emption of subsurface storage space*: Since a given geological formation has a finite capacity for accepting injected fluids, its use as a disposal reservoir can preclude use for other types of storage.
- *Subsurface pressure alterations*: Fluid waste injection will generally result in an increase of the reservoir pressure. The most important potential effects of pressure increases are stimulation of seismic activity, formation fracturing and migration of resident fluids.
- *Chemical compatibility problems*: Geochemical or biochemical interaction between waste and rock.

Potential adverse effects of underground CO₂ storage in relation to safety and/or environmental damage can be categorised into five groups:

- escape of CO₂ to the atmosphere
- CO₂ pollution of groundwater or other underground resources
- seismicity
- subsidence or absidence of the earth surface
- degradation of the storage reservoir underground

Escape of CO₂ to the atmosphere can occur from all parts of the of the storage system. Pollution of underground resources, particularly potable groundwater, will be a matter of concern in the subsurface part of the system (wells and reservoir).

6.3.1 Escape of CO₂ to the Atmosphere

A major risk from the leakage of large amounts of CO₂ to the surface is suffocation of human beings or animals. At surface conditions CO₂ is heavier than air. It therefore tends to cling to the earth's surface, forming a blanket-like cloud that flows into and fills topographic depressions. In

this way pools of CO₂ may develop in valleys from which all oxygen has been driven away. At first, the danger of these clouds will not be noticed, because CO₂ is a colourless and odourless gas. Natural releases of large amounts of CO₂ occur in volcanic areas. The 1986 disaster in Cameroon caused by a sudden escape of large amounts of volcanic CO₂ from Lake Nyos, killing more than 1700 people, illustrates that, under certain rare circumstances, CO₂ clouds may form a very serious hazard.

If we consider an amount of 100 Mt CO₂ stored underground (ca 25 years CO₂ production from a 500 MW coal fired power station) and assume that it is somehow possible that this stored amount could escape from the reservoir and reach the surface in a very short time, CO₂ release could result in a cloud of ca 50 km³, which may in the most unfortunate case (with a cloud thickness of 3 m) cover an area of roughly 18 000 km². The disastrous effect of such a cloud in populated areas is obvious, but the likelihood of such a disaster is very small. The escape of almost all CO₂ that has been injected over 20 years is impossible in a short time due to the limitation of the injection system. The successful capping of the burning Kuwait oil and gas wells have shown that escapes from wells can be controlled even when the controlling safety valves have been destroyed. In the case of CO₂, a leak may be partly obstructed by the formation of dry ice, thus reducing the rate of release. However, the Cameroon case shows that modest CO₂ releases can be captured in deep lakes in which the amount of CO₂ may gradually build up and that a sudden release of the thus accumulated CO₂ may have a disastrous effect. Fortunately, most lakes are confined to depressed areas and most CO₂ released will therefore stay above the lake.

Another risk related to CO₂ escape is instant freezing of plants, animals or human beings in the direct vicinity of the leak, due to the temperature drop caused by expansion of the liquid CO₂. The rapid CO₂ expansion may cause the formation of dry ice.

Escape of large quantities of CO₂ to the sea bed would likely be less damaging to the human population than escapes to the ground surface on land. The major effects might be a decrease in pH of the seawater near the escape, combined with possible return of CO₂ to the atmosphere. The sudden escape of large quantities of CO₂ into seawater could theoretically reduce the density of the seawater and pose a transient hazard to passing shipping.

6.3.2 Groundwater Pollution

Potable groundwater is generally found in the top 100–200 m of the subsurface. This fresh water could be contaminated by leakage of free CO₂ from either the injection system (i.e. injection wells) or the storage reservoir. Clearly, the effects of adding CO₂ to a groundwater will depend to a large degree upon the water/rock interactions. These will in turn vary widely, reflecting the wide range of lithologies which may act as groundwater aquifers. Therefore it is not possible, within the scope of this report, to consider the effects of CO₂ leakage in all types of aquifer.

A large number of factors must be considered when attempting to evaluate the potential effects of CO₂ leaks from disposal sites upon the quality of potable groundwaters. The most important processes are likely to be:

- perturbation of groundwater flow regimes
- migration of saline waters with CO₂

- migration of dissolved organic matter with CO₂
- mineral dissolution
- co-precipitation of metals
- sorption of metals
- microbial activity
- aqueous complexation of metals

Analysis of the above reveals that there are four basic underlying factors which must be considered when evaluating the significance of CO₂ disposal for the potability of groundwaters:

- pH buffering
- redox buffering
- fluid flow
- transport of pollutants (e.g. hydrocarbons).

In particular, the effect of CO₂ addition on pH and redox conditions is likely to be a major control on groundwater quality.

Dissolved oxygen exerts a major control on the mobility of many elements. Cu, V, U and Cr were found to be mobile under oxidising conditions, but to occur at very low concentrations under anaerobic conditions. However, other elements, such as Fe, are mobile only under reducing conditions. Several elements, including Mn and Zn were found to be relatively insensitive to redox changes.

The concentration of many trace elements in groundwaters increases with increasing acidity. However, because different lithologies have different chemical characteristics and pH buffering capacities, the behaviour of trace metals was found to depend to some extent upon the nature of the aquifer. For example, in carbonate aquifers most of the toxic elements were found to be buffered at low levels by the carbonate system, except for F, Sr, I, and B. In contrast, waters from sandstones tend to show higher concentration of many transition elements (e.g. Fe, Mn, Cu) than in waters from carbonate aquifers, regardless of the pH. However, as pH decreases to < ca 6, dissolution of the sandstone matrix is inferred to cause significant increases in concentrations of metals such as Al, Zn, Be, Co, Cr, Ni and V.

The hydraulic regimes which operate in most likely sites for CO₂ disposal will be distinct from those in areas where potable groundwater is abstracted. Formation water in potential CO₂ storage reservoirs will generally be deep, highly saline, ancient and slowly moving. In contrast, potable groundwaters are typically shallow, fresh, young and rapidly moving. Additionally, where disposal sites are located in depleted offshore hydrocarbon reservoirs, usually they will be located a long way from sites of groundwater abstraction. Thus, in many cases it is unlikely that CO₂ leakage from disposal sites will have a significant effect on groundwater quality. However, it is possible that leakage of CO₂ into potable groundwaters may occur from onshore reservoirs or reservoirs which lie only a short distance offshore. Additionally, the injection of CO₂ might conceivably alter the hydrogeological regime sufficiently to influence groundwater quality indirectly. For instance, transition zones between shallow fresh, and deeper saline waters might move. Such hydraulic variations might themselves lead to CO₂ leakage. The assessment of the possible importance of such perturbations to fluid flow will not be a trivial task. This is partly because in-situ fluid flow in deep

formations cannot be measured directly, but must be evaluated by means of theoretical models.

Similarly, it will be difficult to assess accurately the likely impact on groundwater quality of pollutants which might migrate with leaking CO₂. This is because of the large number of factors which must be taken into account. Any assessment must consider the possible multi-phase nature of flow and the wide range of possible pollutants (e.g. trace metals, organic acids, petroleum, organic gases, and liquid petroleum). Nevertheless, it has been possible to draw the following tentative conclusions:

- The leakage of CO₂ into potable groundwater supplies is most likely to be a problem when CO₂ disposal takes place on land
- Carbonate minerals and Fe-oxides are likely to exert important controls on groundwater quality in both sandstone aquifers and carbonate aquifers
- It is possible that CO₂ leakage may transport heavy metal pollutants from ore deposits into nearby potable groundwater supplies
- Even small leaks of CO₂ from underground disposal sites may possibly cause significant deteriorations in the quality of potable groundwaters

6.3.3 Seismicity

Underground disposal of CO₂ requires the control (if possible) of the physical and chemical modifications of the reservoir. This is essential for safety and long term disposal. It is well known that injection of large amounts of fluid into a sediment layer or fractured rock modifies its mechanical state. High pore-pressure gradients in or around the reservoir may induce micro-earthquakes and even damaging earthquakes. The process may be enhanced by contraction of the rock due to cooling by 'cold' injection fluids. Possible induced seismicity may damage the injection wells.

Studying induced seismicity has two aspects. The most important is seismic hazard assessment. The other aspect is *in situ* monitoring of the mechanical behaviour of the reservoir. The latter is not yet obligatory, as it needs more sophisticated technology and is still at an experimental stage. Both aspects require careful examination of the conditions at the disposal site, i.e. historical seismicity, structural study of the area, evaluation of the critical fluid pressure for failure, and pre-injection seismic monitoring of the area to define the 'zero state' seismicity. In addition, modifications of the reservoir state should be examined if it is a pre-exploited reservoir. During disposal operations a combined network of subsurface and downhole sensors can be installed to monitor induced seismicity. State-of-the-art seismological monitoring allows real-time determination of the location of hypocentres, with either a surface network for large events, or downhole sensors for microseismicity. The surface network is mainly designed to assess and prevent seismic hazards, the subsurface network to study reservoir processes in detail.

6.3.4 Subsidence or absidence of the Earth's surface

It is possible that the earth's surface will sink or rise because of man-made pressure changes in the subsurface. Several cases of subsidence are well known and exten-

sively documented. Examples are the Ekofisk oil field and the Groningen Gas field. For all these cases, the mechanism is well understood, but prediction of subsidence is found to be difficult. The data on absidence are limited, but it is understood that here the same theories can be applied as for subsidence.

The main phenomenon of this rock transformation is the change in pore space. As a result, the earth's surface may sink or rise, depending on factors such as formation thickness, areal extent of the compaction, depth of the formation and the characteristics of the overburden. For CO₂ injection, only an increase of the fluid pressure needs to be considered. Subsidence due to pressure changes is therefore not expected. It is further not envisaged that absidence will take place in a CO₂ reservoir as long as the maximum storage pressure is kept below the geostatic pressure (= initial overburden pressure), implying that the incremental reservoir pressure will always be less than the original grain pressure and the grain pressure will remain positive. However, in a reservoir that is under high tectonic stresses, any significant reduction of the grain pressure may trigger faults. This may lead to up-lifting or down-faulting of the surface, depending of the nature of the tectonic regime.

Another cause for subsidence may be dissolution of the reservoir rock (chemical compaction). For example, in an underpressured gas reservoir the load of the overburden may be supported by the strength of the rock framework. If the rock framework is leached by aqueous CO₂, the reservoir may compact under the weight of the overburden formation. Chemical compaction will particularly be a matter of concern in carbonate rocks with a high (secondary) porosity, but grain-to-grain pressure solution may also be enhanced by a decrease of the pH in siliciclastic rocks. If overpressured hydrocarbon bearing carbonate rocks become underpressured and saturated by carbonated water, they are likely to undergo chemical compaction.

6.4 SAFETY AND STABILITY OF THE STORAGE SYSTEM

The storage system is subdivided into three specific parts in order to evaluate the risks and safety measures associated with each individual part. These parts are: 1) the surface installations and equipment; 2) the injection system (i.e. mainly the injection wells); and 3) the storage reservoir. The malfunction of any part of the storage system could require that the CO₂ from the power station be temporarily vented to the atmosphere, as it is at present.

6.4.1 Surface and Injection Installation

A CO₂ storage system will require a surface installation consisting of a CO₂ transmission pipeline, a CO₂ delivery station, a pipeline distribution network and a monitoring system. After being processed and compressed, the CO₂ output from a power plant will be brought through the CO₂ transmission pipeline to the central delivery station at the disposal site. At this station, the quality and quantity of the CO₂ must be controlled. Depending on the quality, some additional treatment may be necessary, such as filtering, introduction of inhibitors or re-compression. The pipeline distribution network will be needed to carry the CO₂ to the individual injection wells. The monitoring system will control pressure and flow during the CO₂ injection process.

6.4.2 CO₂ Transmission Pipelines

For consideration of CO₂ leaks from pipes the following definitions of types of pipe defect are adopted: 1) pinhole or crack (diameter up to 20 mm), hole (diameter from 20 to 125 mm), and 3) rupture (diameter larger than 125 mm). In a CO₂ disposal pipe with a 250 mm diameter, the total amount of liquid CO₂ (10°C, 10 MPa) between two adjacent isolation valves would be about 3000 tonnes (ca 1 500 000 Nm³). In the case of a 'pinhole' failure, CO₂ would escape at a rate up to about 6 kg/s. It would take about 150 hours for the section of pipe to discharge all its CO₂ and the escaped CO₂ would probably disperse into the surrounding air until the leak was identified and repaired. Failures of the 'hole' type would involve CO₂ release rates of 6 to 240 kg/s. The CO₂ in the pipe between two shut-off valves would be discharged in a period ranging from 150 to 3.5 hours. Failures of the "rupture" type would release up to 10 tonnes CO₂ per second and the CO₂ from one pipe section could be discharged in 10 minutes. In such circumstance the liquid CO₂ would be subject to adiabatic expansion which would result in the release of 67% of the CO₂ in the vapour phase, 30% as solid CO₂ snow at the site of the rupture and 3 % remaining as CO₂ snow inside the pipe. The temperature resulting from rapid adiabatic expansion of liquid CO₂ to atmospheric pressure would be -56°C.

Simulations of CO₂ release from perforated pipelines (CO₂ pressure = 10 MPa, CO₂ flow rate = 220 t/hr, hole size = 10 mm, pipe diameter = 1 m, discharge = 1.5 kg/sec, wind 1 and 10 m/sec) showed that the 'Immediate Danger to Life and Health' figure for CO₂ (3 to 5 vol%), was reached at ground level only within 50 m of the source. This exercise showed that CO₂ losses from a small leak would result in ground level concentrations which would not constitute a significant risk to life. A similar theoretical simulation would need to be carried out to predict the dispersion of CO₂ from a large discharge.

Much information on pipeline incidents in Europe has been provided by companies that distribute natural gas. The incidents are classified by cause:

- *External interference*: breach of the transmission pipe by some external agency e.g. accident or agricultural activity
- *Hot tapping*: in advertent breaches of the pipe by utility workers mistaking the pipe for, say, a water pipe
- *Corrosion* (more prevalent in older pipes)
- *Construction defect* (including defects in materials); these failures are more prevalent in pipes constructed before 1970
- *Ground Movement*; only in areas of high geological activity

To estimate the likelihood of the occurrence of a pipeline failure of sufficient magnitude to potentially create a hazardous cloud of CO₂, the following assumptions are made: 1) all 'ruptures' cause large losses; 2) the largest 10% of 'holes' cause large losses; 3) the frequency of failure due to external cause for a 250 mm pipeline is 70% of the overall frequency of failure by external cause; 4) experience in pipeline design, protection and siting means that the failure frequency of future pipelines is 10% of that

of pipelines in the past. On the basis of these assumptions the estimated frequencies of occurrence of large losses are about 11 per million kilometre-years. Therefore the estimated frequency of a major incident occurring involving large losses of CO₂ from a 75 km long pipeline is once every 1200 years.

6.4.3 Surface Equipment at the CO₂ Disposal Site

On top of the CO₂ storage reservoir, a central CO₂ delivery station will be required to control the quality and quantity of the delivered CO₂. It should be sufficiently equipped to enable the operator to test and service the wells in normal operations without delay. Some additional treatment may be necessary, such as filtering (removal of solid particles to prevent well clogging), the introduction of inhibitors, or re-compression. Apart from this delivery point, a pipeline distribution network will be needed to transport the CO₂ to the individual injection wells. A pressure and CO₂ flow monitoring system will additionally be required to control the CO₂ injection process.

Malfunctioning of the surface system can cause CO₂ leakage to the atmosphere. Possible causes are: 1) leaking connectors and appendages; 2) unsuitable and leaking materials; 3) unsuitable construction and execution; 4) decay of materials through time; 5) external damage to pipelines caused by, for example, digging and/or building activities. Malfunctioning of the system can be reduced by rigorous maintenance and the use of suitable high quality materials. Special precautions against corrosion, such as internally coating the pipe or using special steel, do not appear to be common operating practice, except when the CO₂ is 'wet' or high concentrations of H₂S are present. If the surface system fails, the presence of safety valves will ensure that only a small quantity of CO₂ will be released to the atmosphere. CO₂ will be at a relatively high pressure in the system, so a failure will cause a rapid pressure drop in the distribution system. A simple additional device integrated in the pressure monitoring system could close off the failing subsystem. The amount of CO₂ released will thus be restricted to the contents of the failing subsystem.

6.4.4 The Injection Installation

The injection installation will consist of a number of wells that have to be drilled in order to inject the CO₂ into the underground reservoir. With modern directional drilling techniques, the surface location does not have to be directly above the point where the drill hole penetrates the target formation. For practical and environmental reasons it is very attractive to keep the surface activities confined to a small area. So, if possible, all new wells should be drilled from the same location, i.e. from one drilling platform.

The injection well system will generally follow local high pressure gas practice, with special attention to corrosion control. It is important to verify whether the cement has been placed adequately around the casing to avoid that CO₂ leaks through the space between the casing and the wall of the bore hole. The cement job has to be of a very high quality where the casing passes through the cap rock of the reservoir, preventing CO₂ from invading the overburden formation. Injection will take place through an injection or tubing string that runs through the casing. The space between the tubing and casing is sealed off from the CO₂ with a packer. This space forms an important barrier between the CO₂ and the subsurface. Monitoring the

pressure behaviour in this space will indicate CO₂ leakage from the injection string.

The following situations could lead to the failure of the well during injection and could subsequently cause the rocks above the storage reservoir to be contaminated by CO₂: 1) unsuitable construction and/or execution; 2) leaking pipe connections; 3) defective materials; 4) collapse of the well; 5) human failure. Malfunctioning of the well injection system can be reduced by a high level of maintenance and the use of well selected materials.

Wells that penetrate rock-salt need special attention. Due to its plastic behaviour, the salt could cause wellstrings to collapse. Earthquakes or ground movements may have the same effect and there have been many examples of casing collapse in oil and gas fields caused by shear along faults intersecting the well. If the well fails, large amounts of CO₂ may escape. The CO₂ in the underground reservoir may escape until the in situ pore pressure equals the hydrostatic pressure on the formation. Leakage can be detected from the pressure/flow history of the well. Safety valves installed at regular intervals in the well, could limit the amount of escaping CO₂. If CO₂ escapes from the injection system, the CO₂ will migrate upwards due to its relatively low density. CO₂ will go into solution where it passes through groundwater bearing formations.

In the majority of well failure cases, the amount of CO₂ released will be very small, i.e. an amount equal to the content of the well tubing. In normal cases such a leak will be detected by the monitoring system, resulting in the closure of the back flow preventer and the emergency shut-down valve at the well head. In that case, most leaked CO₂ entering the rock formation will be absorbed by the formation water. Failure of the back flow preventer, the packer or the cement between the casing and the caprock will have a much greater impact. The first two problems may result in a well blow-out. The wellhead must be designed in such a way that it is able to handle the CO₂ reservoir pressure. Repair of such a mechanical problem is more simple than in case of an oil or gas well, because CO₂ is non-combustible and non-toxic.

6.4.5 The Storage Reservoir

The basic principle of storage implies that the material that has been stored stays at a pre-defined storage location. In almost all storage cases, processes are taking place which are in conflict with this principle. If no special measures are taken, most materials degrade in time. These degradation processes are taking place in the material that is stored and in the storage container, and may be induced or enhanced by changes in temperature, pressure and volume. In all cases they have a negative effect on the storage integrity, i.e. the stability of the storage activity. In case of underground CO₂ storage the following processes can be identified:

- 1 Processes affecting the condition of the stored CO₂. Important factors are reservoir temperature, reservoir pressure, residual components and possible chemical influence of formation fluids and rock on CO₂.
- 2 The interaction of the CO₂ on the rock and subsequently on the fluid flow parameters of the reservoir rock.
- 3 Processes which have an influence on the storage boundaries, e.g. geochemical reactions influencing the sealing capacity of the caprock.

- 4 Processes induced by movements of the earth crust such as tectonic activities and/or microseismic events.
- 5 Processes which are a direct result of human activities. Examples of these processes are overfilling, hydraulic fracturing of the caprock, an incomplete understanding of the geological environment or topology, such as unobserved open faults or spillpoints.

All above identified processes could cause CO₂ to escape directly or indirectly from the storage reservoir. Normally, all known effects of CO₂ storage in the subsurface will be taken into account in the design of a storage site. However, it will be impossible to reduce the risk of CO₂ leaking from the reservoir to zero. So, it is important to evaluate what will happen if CO₂ does leak into adjacent formations (see Section 6.5 p.17).

6.4.6 Reservoir Selection

When considering a CO₂ injection project, the first task would be to find a safe storage reservoir. Several factors must be considered if a CO₂ storage reservoir has to be selected. One of the most important is the extent and the quality of the seal of the proposed reservoir. For oil- or gas fields, the properties of the seal are already known. In the case of aquifer storage, the knowledge of the cap rock characteristics will generally be limited and an extensive survey will be needed to fill in this gap. Another limiting factor will be future environmental legislation. There should be: *'conclusive technical evidence to demonstrate that waste injection will not interfere with present and potential use of water resources or result in other environmental hazards'*. Some countries will permit underground CO₂ storage only if the process is reversible. This requires CO₂ confined to a fixed storage area, which implies a trap which stops fluid migration.

Onshore, the most suitable structures for storage of carbon dioxide are large traps on highly permeable aquifers at depths of 800 m or more. Such structures are almost identical to those sought in petroleum exploration. Since the problem of defining traps for petroleum exploration and CO₂ storage are almost identical, the exploration techniques used in the oil industry will be those suited for CO₂ disposal. Seismic reflection profiling is the standard and preferred technique used by the oil industry to delineate traps which might contain oil or gas. These profiles provide a two dimensional (2-D) section through the earth, typically to depths of 5 km or more. Intersecting networks of 2-D profiles are commonly acquired, so that a 3-D interpretation of the subsurface structure can be made. A major drawback of seismic data is that they are expensive to acquire.

Other geophysical techniques, such as gravity, magnetic and electrical conductivity surveying play a minor role under certain favourable circumstances. Their major advantages are low costs and simple data acquisition. They generally provide, however, data that are less detailed than seismic data and should therefore be considered as complementary to a seismic survey. Although seismic data are capable of providing much superior resolution, particularly in the depth range of interest, they may not always be available or of sufficient quality in the areas concerned. So, the application of non-seismic techniques to locate CO₂ disposal sites will be largely determined by the amount of existing information. They are not capable of defining the details of aquifer and cap rock character-

istics or structure, but they can be effective in the assessment of unexplored ground and in augmenting the results of other studies to establish the structural framework.

6.4.7 Reservoir Monitoring

Large-scale storage of CO₂ in the subsurface is an unprecedented enterprise. It will therefore be crucial to monitor the process carefully. The major task of monitoring is to record and control the stability of the reservoir and to observe the development of the expanding CO₂ bubble. The stability of the reservoir can be monitored by looking at the seismicity. It will be important to understand the source of seismicity, because only then can an effective control on the seismicity be achieved. The system must be able to monitor the reservoir in such a way that it is possible to pinpoint the hypocentre of a seismic event and to answer questions such as: 'Is the seismicity natural or reservoir induced? Does it originate from 'hydraulic fracturing', an 'effective stress' mechanism or from 'stress loading'? Does it correlate with the injection activity? It will be important to follow the development of the expanding CO₂ bubble to check if the preliminary injection models correspond with the real situation and to ensure that CO₂ remains in the reservoir and does not escape to the overburden formation where it may endanger potable ground water resources. Regular checking of reservoir simulations enables a continuous modification and fine-tuning of the models.

The various examples of induced seismicity have shown that although this appears commonly as a result of underground fluid injection, damaging earthquakes are not common. Each instance of reservoir-induced seismicity is a special case strongly dependent on local geological conditions. As far as underground gas storage is concerned, seismic hazard can be regarded as very low, since gas is highly compressible, injection pressures are low and the reservoir would be sited in a quiet tectonic environment. However, damaging induced earthquakes have been recorded in and around hydrocarbon reservoirs after some tens of years of exploitation, which justifies paying special attention to seismic monitoring prior to, during and after CO₂ disposal. The state of the art of seismological instrumentation, downhole sensors and computers is such that it is now possible to design a combined downhole and subsurface network dedicated to producing real-time processing of seismic signals and location of micro-earthquakes. Even if the frequency of seismic events is low, this would quickly give information on mechanical modifications of the reservoir, i.e. the location of zones where the reservoir is becoming fractured and the critical pressure needed for failure and earthquake generation.

A way to visualise the development of the CO₂ bubble is by shooting seismic lines across the storage site. The behaviour of a CO₂ bubble in an underground reservoir is in many ways analogous to the bubble of natural gas in a gas storage scheme. The presence of natural gas in the pore spaces of a reservoir, as opposed to water, can be detected by seismic methods, because gas and water have different densities and sonic velocities. This may create sound

waves reflections at the gas/water interface. Even low levels of gas saturation are sometimes sufficient to create a reflection. In oil and gas exploration, these seismic reflections are considered to be reliable gas indicator.

6.5 SUBSURFACE RETENTION TIME OF ESCAPING CO₂

The safety and stability aspects of CO₂ storage activities can be approached in two ways. One way is to consider all possible factors that have a negative influence on the stability of the storage activity. A second approach is to evaluate the effects of a breakdown of the stability of a storage reservoir and to study the effects of an uncontrolled release of CO₂ in the subsurface, i.e. how and when does this CO₂ reach the surface?

A simulation study was performed to estimate the subsurface retention time of CO₂, either injected into the subsurface without being confined by a trap, or leaking from a geological trap at a spillpoint, at a depth of 1000 m. The outer boundary of the model is located at a distance of 4750 m from the centre of the spillpoint. An injection well is positioned in the middle of the model, at a depth of 1000 m. The total injection or spillage rate amounts to 5.82×10^6 Nm³/d for a fully 3-dimensional situation.

A base case model was created to be used as a reference. All grid cells were assigned a constant permeability of 1 μm² (Darcy) and a porosity of 35 %. This high permeability was chosen with the aim of creating a worst case in relation to the expected retention time. The total CO₂ injection time is 365 days, with a total of 2.124×10^9 Nm³ CO₂ injected. The calculated breakthrough time or CO₂ retention time is less than 731 days. Analysis of the pressure behaviour of the subsurface fluid between the spillpoint and the surface reveals only a small pressure increase at the start of the leakage. Most simulated time intervals show a reduction of the hydrostatic gradient caused by the inclusion of the lighter (residual) CO₂.

A second, more realistic model was based on the permeability distribution of the Dutch subsurface (northeastern part of the country). Individual layer thicknesses were used to reflect the probable geological stratigraphy. The same CO₂ injection data were used as in the base case. In this case, however, the injection period had to be much longer (30 years) to inject the same amount of CO₂, because the injection block was much less permeable. The simulation results show that the escape of CO₂ is appreciably delayed by the low permeability of clay layers. The resulting breakthrough time for the modelled Dutch subsurface is about 5 500 years. It is clear that the retention time of CO₂ injected in the subsurface largely depends on the geological layers with the lowest permeability and the thickness of these layers. The fluid pressure profile for the area above the spillpoint shows initially a large pressure increase as a result of the injection. This proves that a large pressure contrast is needed between the storage reservoir and the spillover area to maintain a substantial leak-off rate for a longer period in low-permeability areas. After the leakage has stopped (after the injection period of 30 years) a stable pressure profile is achieved.

7 Inorganic geochemistry of the underground disposal of carbon dioxide

The technical feasibility of the underground storage of CO₂ will depend strongly on the chemical reactions that occur between the formation water, minerals and supercritical CO₂ in the reservoir. Such reactions could affect the injection process, for example by reduction of permeability due to the precipitation of clay minerals, or dissolution around the well bore. They could also affect the stability of storage if they adversely affect the strength of the reservoir rock matrix. The entrainment of elements or compounds by the addition of CO₂ to formation water could affect its ability to pollute, for example, potable water. The dissolution of CO₂ into formation water could affect the storage capacity of reservoirs, and also the reaction of carbonated water with Ca-rich minerals or Ca-rich formation fluids could provide a means of permanently fixing CO₂ underground, by the precipitation of carbonates.

We adopted a combined experimental and computer modelling approach to help us understand the geochemical processes which might occur as a result of CO₂ injection. The experiments varied from simple long term batch experiments to more complex core flood experiments. Interpretation of the results of the experiments was aided by the use of purely geochemical computer models and coupled reaction-transport models, which allowed us to extend the experimental results and make reservoir-wide predictions.

7.1 THE SOLUBILITY OF CARBON DIOXIDE

Dry supercritical CO₂ is relatively inert, and as such would tend not to react with reservoir rocks, and hence not be locked up as carbonate minerals. A key factor in the conversion of supercritical CO₂ to carbonate minerals is its ability to dissolve in water. Although supercritical CO₂ is a non-ionic solvent, it will dissolve into formation water. However, the degree to which the CO₂ will dissolve is dependent on the salinity of the water, dilute solutions being able to dissolve more CO₂. Temperature and pressure are also crucial parameters in determining how much CO₂ will dissolve. In general, higher pressures lead to higher solubilities. The effect of temperature is more complex and, for the likely conditions found in potential reservoir rocks, gives rise to a solubility minimum in the region of 100°C. Such complex relationships will result in solubility being reservoir specific. However, taking 80°C and 200 bars pressure as being representative of many potential Southern North Sea reservoirs, maximum CO₂ solubility in pure water is equivalent to approximately 5.1 g of CO₂ per 100 g of water, or approximately 1.5 g of CO₂ per 100 g of water for a 2 molar solution of NaCl (i.e. approximately four times seawater salinity).

One consequence of such solubility is that much CO₂ could be stored in dissolved form as well as in the free supercritical fluid phase. Theoretical calculations for a reservoir 100 km long, 5 km wide, 100 m thick and with 10% porosity, indicate that about 0.25 Gt CO₂ could dissolve in the entire pore volume of the reservoir. As outlined above in section 4.3, a high degree of dissolution would be

beneficial, in that a discrete stratigraphic or structural trap need not be present in order to dispose of CO₂.

Experimental observations suggest that the CO₂ dissolution reaction is several orders of magnitude faster than mineral dissolution reactions. But the timescale over which maximum dissolution might occur in the reservoir is uncertain. The processes affecting rates of CO₂ dissolution into formation water on the reservoir scale are likely to be dominated by how much free CO₂ has access to undersaturated formation water in the reservoir, i.e. the speed and the manner in which the injected CO₂ mixes with the formation water at the CO₂ front.

7.2 MINERAL REACTIONS, THEIR EFFECTS ON THE POROSITY AND PERMEABILITY OF THE CO₂ STORAGE RESERVOIR, AND THE POSSIBLE INCREASE IN CO₂ UPTAKE

The reactions which will take place in the host formation will be reservoir specific, as they will depend on factors such as the detailed rock mineralogy, rock texture, chemical composition of the formation water, reservoir temperature and pressure and flow rate. However, our experiments and modelling, and an extensive literature review, indicate that carbonate and sandstone reservoirs will behave differently and caprocks will remain relatively stable.

7.2.1 Carbonate reservoirs

Carbonate minerals will dissolve near the injection wells and the formation water will become saturated with respect to these. As the formation water moves along the flow path (away from the injection wells), carbonate minerals could precipitate as the pressure is reduced, or if the temperature is increased. Porosity and permeability should be enhanced in the vicinity of the injection wells, but could be decreased by precipitation of carbonates due to local variations of pressure and temperature in the reservoir further along the flowpath. Therefore, pressure, and to a lesser extent, temperature are crucial parameters to monitor in order to optimize the storage process in a carbonate reservoir, especially as the kinetics of carbonate precipitation and dissolution are fast relative to aluminosilicate minerals.

As pointed out in section 6.3.4 above, the porosity and permeability increase around the injection wells could become so great as to cause subsidence of the ground surface.

Gunter et al. (1993) have calculated that, for a closed system, reaction between mineralogy and formation water for a carbonate aquifer does not significantly increase CO₂ uptake. This was confirmed by numerical simulations carried out in our study. However, this is not the case for sandstone reservoirs.

7.2.2 Sandstone reservoirs

Injection of CO₂ into a sandstone reservoir will cause dissolution of feldspar grains, dolomite and anhydrite

cements, and subsequent precipitation of clays, carbonates and quartz (or another silica phase). Where leaching is most intense (e.g. in the central zone of fingers of CO₂-rich fluids within more permeable pathways) kaolinite would be the major clay phase. However, where leaching is less intense (e.g. at the edges of the storage zone or between the CO₂-rich fingers), or where the temperature is above 110–140°C, illite or chlorite would be the major clay phases. Observations of natural CO₂ reservoirs (Norphlet Formation, USA) indicate that a decrease in permeability may result from these mineral transformations, due to the formation of authigenic clays.

The complex set of mineral reactions in a sandstone formation has a greater buffering capacity compared to carbonate formations, and thus favours the dissolution of CO₂ into water by the formation of bicarbonate ions and bicarbonate complexes. Therefore more CO₂ could be stored in dissolved form in sandstone reservoirs than in carbonate reservoirs. However, the efficiency and reaction time of the buffer system could be slow (though still fast on a geological timescale), as they depend on the reaction rates of aluminosilicate minerals.

Mineral trapping by calcite precipitation would also increase CO₂ uptake and ensure permanent storage, but this would only be possible in aquifers with Ca-rich formation waters or with very specific mineralogical characteristics. In the types of reaction mechanism proposed by Gunter et al. (1993), Ca-feldspars react with CO₂ to form calcite and kaolinite. However, host formation sandstones will probably only contain traces of Ca-rich feldspars as these tend to be altered easily during rock diagenesis. In the experimental part of this study Ca-feldspar was not present to an appreciable degree, and K-feldspar was the main silicate phase undergoing dissolution. Reactions involving K-feldspar and CO₂ did not result in calcite precipitation directly. Dedolomitisation reactions did appear to cause some precipitation of calcite, though this was not large. However, other experiments in this study have shown that an increase in CO₂ uptake through carbonate precipitation could be achieved in sandstones rich in anhydrite cement. Such a reaction mechanism could be very important as anhydrite cement is a common feature in many sandstone formations and, being a sulphate mineral, has a fast dissolution rate compared to silicate minerals.

Data gained from enhanced oil recovery projects and from the core-flooding experiments suggest that rock porosity should increase in the vicinity of the injection wells, with improvement of injectivity, due to the dissolution of calcite and dolomite cements. The experiments

reported by Bowkwer and Shuler (1991) on CO₂-flooding showed that carbonate minerals dissolved along channels corresponding to preferential bands of more poorly cemented rock. Therefore, depending on the rock texture and mineral kinetics, which are more rapid for carbonates than for silicates, carbonate minerals may tend to dissolve initially, either in the vicinity of the injection well or locally within the reservoir.

7.2.3 Caprock integrity

The injection of CO₂ into a reservoir will result in an expanding volume of supercritical fluid. Being less dense than formation water, this fluid will rise within the host rock until it reaches a low permeability lithology. This could be the caprock for the formation and it is important to demonstrate that its integrity will not be compromised by the presence of CO₂. Investigation of the effect of CO₂-rich fluids on mudstones revealed little reaction with the clay phases, although ion exchange reactions and changes in the swelling properties could be important. However, dolomite and K-feldspar within the mudstones were dissolved. The presence of natural CO₂ fields, and large-scale enhanced oil recovery operations using CO₂, suggest that mudstones are not severely affected. For certain reservoirs anhydrite forms the caprock. Numerical modelling has proved that anhydrite would remain stable when in contact with formation waters enriched in dissolved CO₂. Evidence from natural CO₂ fields in the US indicates that CO₂ can be adequately capped by anhydrite over geological timescales. However, it is still unclear as to the effect of the complex reactions that would occur between lenses of anhydrite within mudstones.

7.3 MOBILISATION OF TRACE ELEMENTS

The underground storage of CO₂ may result in the mobilization of trace elements from residual oils or heavy minerals encountered in the reservoir, due to the complexing power of bicarbonate and thiocarbonate and to the solvent properties of supercritical CO₂. This could represent a potential contamination hazard if such heavy metal enriched fluids escaped from the reservoir. However, deposition of base metals could well occur at the edges of the reservoir due to CO₂ degassing when the pressure is reduced. It is also worth noting that if injection of CO₂ was carried out in areas such as the North Sea, there could be significant distances between the injection site and the nearest abstraction sites for potable water.

8 Techno-economic modelling of the underground storage of CO₂

A techno-economic model of the separation, transport and underground disposal of CO₂ has been created for the project. This is available as an Excel spreadsheet. For the techno-economic analysis, the underground disposal of carbon dioxide can be split into three stages: CO₂ recovery at the power station, CO₂ transport and CO₂ disposal. The methodology of calculating the unit costs of CO₂ avoided in the CO₂ recovery, transport and disposal system includes all the capital and operating costs and also the net CO₂ avoided by modifying the plant after taking into account the fact that the electrical output is significantly reduced by the CO₂ recovery operations. Typically the net CO₂ recovered at the modified plant is 90% of its total CO₂ emission, while the net CO₂ avoided is about 85% of the CO₂ emission of the original unmodified plant.

8.1 CO₂ RECOVERY

CO₂ can be recovered from a variety of different power plant types using a variety of different methods; thus there are many possible options (see Section 2.4, Table 1, above). The costs of compression of CO₂ prior to pipeline transport are included in the recovery costs in our economic model. The cost of CO₂ avoided at power stations varies between 25 and 65 Ecu/tonne avoided. There still remain significant debates about the level of costs, parasitics and CO₂ recovery rates which will be achievable in practice, and these may have an effect on these numbers.

8.2 CO₂ TRANSPORT

It is assumed that the CO₂ is collected from a group of power stations as a supercritical fluid using a system of pipelines, and is then fed into a single pipeline to transmit it to the disposal site. All of the initial compression costs and parasitics are included in the power plant calculations. It is further assumed that the collection and transport of CO₂ is carried out with the CO₂ as a supercritical fluid and that the pressure in the pipeline system does not fall below 80 bars. Dynamic friction losses in the pipeline reduce the pressure of the CO₂ and this may need to be restored at intervals with further compression. Because of the expense of compressor stations it is normal to avoid compression offshore as far as is possible. In general, the carrying capacity of pipelines offshore is higher than onshore. This is for two reasons:

There is usually a higher static head gradient in the pipeline offshore, which compensates for the dynamic head loss, leading to an increase in design velocities.

Fluid temperatures are lower and average pressures are higher, hence overall densities are higher.

Overall, the carrying capacity onshore is about 75% of that offshore, and as pipeline costs are broadly comparable onshore and offshore, the unit costs of CO₂ transport offshore are lower than onshore.

8.3 CO₂ DISPOSAL

The main cost at an onshore disposal site is drilling the injection wells. The offshore cost calculations are more complex because a variety of solutions are possible. With existing or exhausted oil and gas fields it may be possible to renovate the existing platforms. These platforms are all either at the end or close to the end of their design lifetimes and re-use would require reclassification, some renovation and possibly significant operation and maintenance costs to extend their lifetime for another 25 years.

Opinion within the industry is that this is a risky and possibly expensive option and that it is safer to assume that new facilities would be installed for CO₂ injection. This is the assumption which has been made in this study. The only exceptions to this are the enhanced oil recovery cases where it has been assumed that the CO₂ re-injection can be incorporated along with the normal platform activities on oil production platforms which have a significant remaining productive life.

For new facilities the main choice lies between subsea completions and simple wellhead platforms. Discussions with the industry have led to the formulation of a set of rules by which the options can be chosen and also costing functions have been defined in each case. Wellhead platforms are used for water depths of less than 150 m and subsea completions are assumed in deeper water.

Jackup drilling rigs are used in water depths of less than 150 m and semi-submersibles in deeper water.

The use of CO₂ in enhanced oil recovery has been suggested by a number of authors as a practical method of disposing of CO₂ from power stations. The reservoir voids left by both the primary and tertiary recovery could accommodate significant volumes of CO₂ and the sale of the oil produced during the tertiary recovery phase will defray some of the costs of CO₂ disposal.

The main methodological problem associated with this case is the treatment of the CO₂ produced during the burning of the tertiary oil production fractions. Two limiting cases can be identified:

The oil produced during enhanced oil recovery is offered on world markets in a way which expands demand and increases CO₂ production. In this case the benefits of CO₂ disposal would be negated by the additional production of CO₂ from the oil which is sold.

The oil produced during enhanced recovery is offered on world markets in such a way that demand does not expand; hence it replaces oil produced by primary or secondary recovery from other fields. In this case no net additional CO₂ is released to the atmosphere as a consequence of the enhanced oil recovery.

The calculations here are carried out on the assumptions of the second case, i.e. production of oil by enhanced recovery does not lead to the net release of CO₂ to the atmosphere.

8.4 CONCLUSIONS

The costs of disposal are dominated in all cases by the costs of recovery of CO₂ at the power station. The costs of pipeline transport and underground disposal are both small in comparison with recovery costs. Transmitting CO₂ 900 km to dispose of it in the Utsira Formation in the Central North Sea — the most remote of the cases considered — gives a transport cost in the order of 15 Ecu/tonne of CO₂ avoided with a disposal rate of 11 Mt of CO₂ per year. The costs of final disposal into the reservoir are in the region of 1 to 2 Ecu per tonne of CO₂ avoided. These

figures indicate that if it is economically acceptable to recover CO₂ from power stations at costs of between 25 and 60 Ecu/tonne of CO₂ avoided, then the additional costs of transport to and disposal in underground reservoirs are not likely to be significant arguments against the underground disposal of carbon dioxide.

The enhanced oil recovery results indicate that if large volumes of CO₂ can be used in major enhanced oil recovery operations displacing oil which would otherwise be produced in other locations, then this could totally defray the costs of CO₂ recovery at power stations, resulting in CO₂ avoidance at near zero cost.

9 Conclusions and recommendations

9.1 CONCLUSIONS

Underground disposal is a perfectly feasible method of disposing of very large quantities of carbon dioxide, such as are produced by fossil fuel fired power plant and most other large point sources of CO₂. All the necessary technological steps are commercially proven. Furthermore, the study of large naturally occurring CO₂ accumulations indicates that CO₂ can be retained in such underground reservoirs for millions of years and CO₂ is injected into underground reservoirs every day for enhanced oil recovery purposes. The concept is so well established that large scale commercial underground CO₂ disposal will begin in 1996, when Statoil start to dispose of approximately 1 million tonnes of CO₂ a year into the Utsira Formation aquifer above the Sleipner Vest gas field in the centre of the North Sea.

In 1990, approximately 950 million tonnes of carbon dioxide were emitted to the atmosphere from power generation in the European Union and Norway. This represents 31.2% of the total EU plus Norway CO₂ emissions of about 3 Gigatonnes of CO₂ (Gt CO₂) per year. Flue gas from today's power plant contains a maximum of about 16% CO₂. It would be both undesirable and impractical to dispose of this flue gas in an untreated state. Firstly, the available storage space would not be big enough to cope with the vast quantities of untreated flue gas. Secondly, there is an overriding thermodynamic argument that prohibits the storage of untreated flue gas. Due to the large volume of the flue gas, the work needed to compress it would be 65% or more of the total work that could be obtained from the coal fired power plant. This would, at best, make it a far more expensive process than CO₂ separation and disposal. Therefore CO₂ would have to be separated from, or concentrated in, the flue gas. The energy required to separate CO₂ from power station flue gas decreases the efficiency of the power plant, meaning that more fuel is required to generate the same amount of electricity. This increases the gross amount of CO₂ generated, such that if 90% of the gross amount of CO₂ generated could be separated and disposed of underground, there would be a net CO₂ avoidance of around 85%.

Shallow subsurface storage of CO₂ as a gas or liquid is considered impractical. There is insufficient gas tight man made void space to store significant quantities of CO₂. The alternative method of storage, disposing of the CO₂ in traps in shallow porous and permeable reservoir rocks, is not practical because they generally have a more important use — for groundwater supply.

Storage in deep porous and permeable reservoir rocks, capped by very low permeability seals, such as clays or shales, is practical. These reservoirs have few present uses and, at typical subsurface conditions, the free CO₂ would be in a dense, supercritical phase at depths of around 800 m or more. This would vastly increase the storage per unit volume of reservoir rock compared to storage at shallow depths. Storage could take place in structural or stratigraphic traps, but modelling suggests these would not be necessary; the CO₂ could simply be injected into certain large essentially horizontal aquifers, for example in the

centre of the North Sea, where it would dissolve into the surrounding formation water before it migrated more than a few kilometres towards the basin margins.

We estimate that there is space available in the European Union and Norway to store approximately 800 Gt CO₂ (which is more than a quarter of the present atmospheric content of CO₂). This estimate is highly provisional — in reality the storage capacity of each reservoir is case specific and requires individual modelling. Only gross generalisations can be made for the European Union and Norway as a whole. Nonetheless, it is clear that there is adequate storage space to cope with CO₂ supply from power generation in Europe for the foreseeable future. The bulk of this storage space is offshore, mostly under the North Sea. As it appears at present about 60% of the storage potential is located on the Norwegian continental shelf and most of the rest offshore UK. However, this is partly because the types of data necessary to identify storage capacity were available and easily accessible in these areas.

Deep underground disposal has the significant advantage that the CO₂ will be deposited in the geosphere, where there is very little chance of it interacting with terrestrial or oceanic ecosystems. Nonetheless, there are some risks to man and the environment attached to the underground disposal of CO₂. These could be minimised by appropriate design and monitoring of all stages of the CO₂ transport and disposal process, using best oilfield practice. Pipeline ruptures, or leaks from surface facilities, are possible, although CO₂ is classed as a low hazard material for pipeline transport in the USA today. The other main risks are associated with the storage reservoir. A slow but persistent leak from an unidentified migration pathway out of a storage reservoir is a possibility. This could be a danger or pollutant at the point where the leak reached the surface, or could pollute potable water above or updip from the storage reservoir. There might be a danger of asphyxiation from the highly unlikely event of a catastrophic release of CO₂ from an onshore storage reservoir. Risks to man and terrestrial ecosystems would be much reduced if storage took place offshore.

The injection of CO₂ into a carbonate reservoir will lead to the dissolution of carbonate minerals in the vicinity of the injection wells and the formation water thereabouts will become saturated with respect to carbonate. As the formation water moves away from the injection wells, carbonates could be precipitated as pressure reduces or temperature rises. Thus permeability is likely to be increased significantly around the injection site, but may decrease further away, towards the reservoir margins. There is the possibility that dissolution of carbonate by prolonged injection of CO₂ into a purely limestone reservoir could eventually cause subsidence around the injection site, particularly when the reservoir pressure around the injection well declines. Injection of CO₂ into sandstone reservoirs is unlikely to cause subsidence.

Injection of CO₂ into a sandstone reservoir will cause dissolution of feldspars and subsequent precipitation of clays and quartz (or another silica phase). The buffering power of aluminosilicate reactions will favour CO₂ uptake into the formation water by the formation of bicarbonate

ions and complexes. Calcite precipitation could ensure (permanent) fixing of carbon via reactions of CO₂ with Ca-rich minerals or formation fluids. Shale and anhydrite cap-rocks sealing the storage reservoirs are not likely to be greatly affected by CO₂/water/rock reactions.

The underground storage of CO₂ may result in the mobilisation of trace elements from oils or heavy minerals encountered in the reservoir, due to the complexing power of bicarbonate and thiocarbonate and to the solvent properties of supercritical CO₂.

The bulk of the costs of storing CO₂ from power station flue gases are at the power station — not in the transport or storage system. CO₂ separation is likely to cost between 25 and 65 Ecu per tonne of CO₂ avoided, depending on the type of power plant selected. CO₂ recovery from a purpose built integrated IGCC plant with CO₂ separation is the least expensive option. The costs of electricity generation from thermal power plant with CO₂ recovery are broadly similar to the costs of electricity generation from wind power. The costs of CO₂ transport are variable depending principally on the length and diameter of the pipeline selected. They range up to about 14.5 Ecu/tonne of CO₂ avoided in our modelled scenarios. The costs of the underground storage process alone are around 1 to 2.25 Ecu per tonne of CO₂ avoided. Modelling of CO₂ storage combined with enhanced oil recovery indicates that if large volumes of CO₂ can be used to recover oil which would otherwise be produced in other locations, then cost credits from the sale of the produced oil could totally defray the costs of CO₂ recovery at power stations, resulting in CO₂ avoidance at near zero cost.

9.2 RECOMMENDATIONS

The next major step in implementing CO₂ storage from power plant should be the demonstration of the storage process. Any demonstration project which started from scratch would be extremely expensive. At a minimum it would require a dedicated source of carbon dioxide, probably a separation plant, a pipeline, a storage site and accompanying infrastructure and injection wells. On top of

this would be the requirements of the research and monitoring programme. The Sleipner Vest and Natuna Sea projects are essentially large scale demonstrations of the practicality of the underground disposal of carbon dioxide. As such they present an unparalleled opportunity for further research into underground storage. Any form of collaborative research with the operators of these schemes would be extremely valuable scientifically and a cost-effective way to verify the findings of this report.

Our primary recommendation is that DG XII of Commission should approach Statoil and Exxon with a view to collaborating scientifically on the Sleipner Vest and Natuna Sea CO₂ storage projects.

Further research is required in the following areas:

1. Geochemical modelling and reservoir simulation of the storage of carbon dioxide in offshore formations, preferably in the North Sea, without the need for a conventional fluid trap (see section 4.4.4). This would require detailed geological data from the chosen formations. It would lead to a refined estimate of the storage potential of the North Sea and a more detailed concept of storage into such formations.
2. Further geochemical experiments and modelling to determine more precisely the effects of CO₂ on the permeability, porosity and stability of reservoir and cap rocks.
3. Construction of a two-phase flow reaction-transport reservoir simulator. This could be achieved by coupling a two phase flow reservoir simulator with the geochemical reaction-transport simulator developed for this project. It would enable simulation of the migration of supercritical CO₂ and water through a carbonate or sandstone reservoir and prediction of the geochemical changes that will occur, and their effect on porosity and permeability. This will allow us to predict, for example, the amount of CO₂ which will dissolve in the formation water of the modelled reservoir and the amount of CO₂ which will be fixed by carbonate-precipitating CO₂/water/rock reactions.

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