A CO_2 Infrastructure for the North Sea

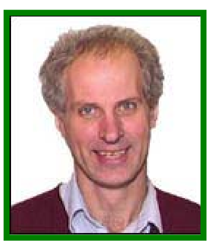
Co-authored by:

Hugh Sharman, director, Incoteco (Denmark) ApS and INCO2 ApS (Denmark, Norway and UK).
B.Sc (Eng), ACGI, civil engineering at Imperial College, London, 1962.
Hugh began his career in the Persian Gulf, during the 1960s, in offshore oil platform construction. Later, in Europe, he was also engaged in other types of marine construction, including lighthouses, subsea pipelines and subsea tunnelling. He launched an unsuccessful renewable energy company in the 1970s. Later, he lived in the Caribbean, developing power stations for small scale countries. He has lived in Denmark since 1986, consulting in energy use and its environmental consequences for major, international companies. With the help of his colleagues at INCO2, Elsam and Kinder Morgan, he conceived the present shape of the CO_2 for EOR in the North Sea (CENS) project. He is grateful to his co-authors for their kind advice and support throughout the development.

Niels Peter Christensen, International Ventures Director, Geological Survey of Denmark and Greenland
MSc in geology; U of Copenhagen, 1980.
Niels Peter has more than 15 years of experience in petroleum geology including work on oil field development in the North Sea and considerable experience regarding chalk reservoirs. He was one of the early pioneers in recognising the potential for greenhouse gas emission reduction through use of CO_2 in enhanced oil recovery and geological storage of CO_2. He is currently project manager of an EU 8 country study assessing their potential for geological storage CO_2.

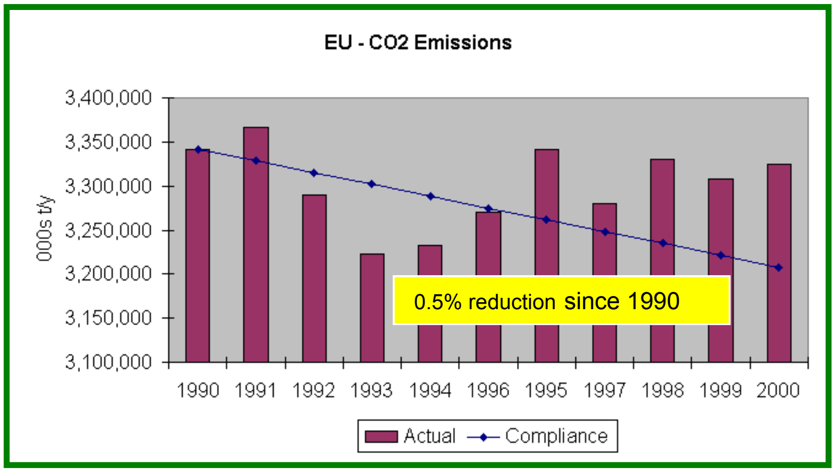
Nicholas Riley, Programme Manager, Reservoir Geoscience, British Geological Survey
Dr. Nick Riley is manager of the British Geological Survey's *Sustainable Energy & Geophysical Surveys Programme*. This programme includes all of BGS's activities in the geological sequestration of CO_2. Since the early 1990's the BGS has been the pioneer UK Centre of Excellence in the underground CO_2 storage (EC Joule 2 Project). The programme currently co-ordinates NASCENT (natural subsurface CO_2 accumulations) and the EC component of the Weyburn Project (a CO_2 Enhanced Oil Recovery project operated by Encana using CO_2 supplied from coal gasification plant) and the technical management of GESTCO (geological storage of CO_2).

Nick Riley publishes by permission of the Executive Director BGS (NERC)



Erik Lindeberg, is Senior Researcher, Experimental Reservoir Technology, Section, IKU/Sintef Group, Norway.
Since receiving his Dr.Ing. in Physical Chemistry at the Norwegian Institute of Technology in 1981, Erik has worked as a Research Scientist with Statoil, with the National Bureau of Standards, Washington DC and since 1985 as a Scientist in the Petroleum Technology Department, PETEK, SINTEF and IKU Petroleum Research. He is a highly respected member of the Norwegian and international petroleum community where his work has been widely published in refereed scientific and technical journals. Erik has been advocating the use of CO_2 as a suitable fluid for enhanced oil recovery (and as a valid CO_2 reduction measure) throughout his professional life and reguarly consults for international oil companies as this technology becomes more widely accepted.

1. Abstract



On 6 December, 2002, the European Environmental Agency (EEA, http://www.eea.eu.int/) published Environmental Issue Report, No 33, *"Greenhouse gas emission trends and projections in Europe*". The conclusion of many experts is that the EU-15 will have great difficulty in collectively meeting its obligation for an 8% reduction in greenhouse gas emissions in a timely manner.

By late 2002, the actual reduction achieved, relative to 1990, was only 0.5%
A few days later, on 10 December, the EU's Council of Ministers agreed to set rules for the first trans-national government carbon trading scheme in the World. These include penalties for the failure of licensed emitters to meet Governmental targets. The penalties are Euro 40 per tonne for non compliant emitters in the period 2005 thro' 2007 and Euro100 per tonne from the beginning of 2008.
(full text at **http://europa.eu.int/rapid/start/cgi/guesten.ksh?p_action.gettxt=gt&doc=IP/02/1832|0|RAPID&lg=EN;)**

This latter value aligns favourably with the UK Government's "Renewables Obligation" carbon avoidance measures placed on UK electricity generators, which at £30/Mwhe, costs roughly Euro120/t CO_2 avoided.

Euro 40 - 100 could therefore be the possible value placed by governments and the EU for sequestered CO_2 when used during the operation of enhanced oil recovery (EOR), if geological storage became accepted as a valid emission reduction strategy. In turn, the reduced net cost for delivered CO_2 could make CO_2 for EOR attractive to oilfield operators. These are faced with declining production and large decommissioning costs, in most of the giant oilfields of the North Sea.

In this paper, the authors speculate that a CO_2 infrastructure, built between 55° N and 62° N, could deliver and sequester up to 40 million t/y CO_2 from industrial installations around the North Sea Basin while producing up to 120 million b/y incremental oil which would otherwise be permanently lost after decommissioning.

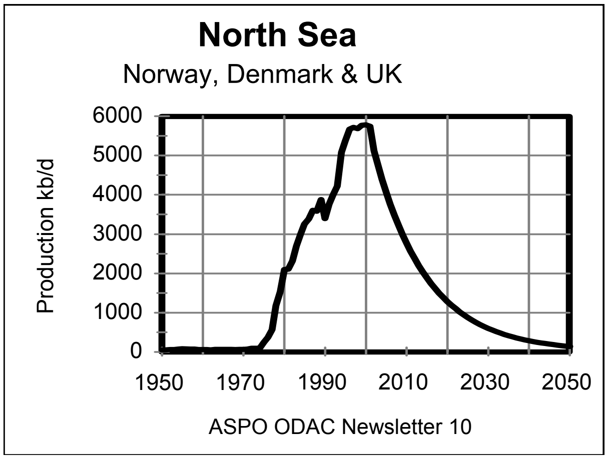
During the lifetime of the EOR operations, up to 1.6 billion t of CO_2 would be permanently sequestered and around 5.3 billion incremental barrels of oil would be produced, delaying decommissioning and saving many thousands of high quality jobs. Natural gas and LPG production would also improve because the CO_2 could be substituted for these lean hydrocarbons which are currently re-injected as an EOR technique, and because the CO_2 is an effective solvent for lighter hydrocarbons that otherwise would be trapped in the reservoir.

The effectiveness of gas injection has been demonstrated widely in Norway. Early injection in some Norwegian reservoirs has resulted in record-high yield of oil in the Statfjord formation on the Statfjord field and the Alpha formation on the Oseberg field, where yields between 85 and 90% can be expected. At present, approximately 40% of all produced Norwegian hydrocarbon gas is being injected. The NPD estimates that 20% of all such injected gas will be permanently sequestered, a huge loss to the Nation.

Many of the injection projects started when there was no infrastructure for gas export and when the gas price was lower. Today gas is sold for a higher price than oil (per energy unit) and a comprehensive infrastructure for gas allows gas export to market from most Norwegian fields. It therefore makes sense to substitute CO_2 for methane as soon as possible, where this is going to be cost efficient.

After all the incremental oil has been extracted, the authors argue that the CO_2 infrastructure can be used to deliver CO_2 into other geological structures for many decades to come.

2.Introduction



The North Sea is among the most important oil and gas producing provinces in the World. During the past thirty years, the extraction of these reserves has brought enormous benefits to the host countries, oil companies, suppliers, technology providers and the treasuries of the host nations. At $25/bbl, oil from the North Sea is currently producing **daily** revenues of about $145,000,000. To this should be added the considerable revenue from gas.

Output of oil from the North Sea Basin is cresting in the three main, producing countries, UK, Norway and Denmark. The UK is now in its second year of production decline.

During the next ten years, unless heroic efforts are made to maintain output, the flow of oil will be halved. The data base of *Oilfield Publications* shows that of the 128 large oil fields studied in this paper, at least 3 have already been decommissioned while no fewer than 35 are due to be decommissioned by 2010. Among these latter are Brent, Embla, Fulmar, Gyda, Fife, Murchison, Siri, Statfjord North and East, Thelma, Thistle, Toni, Tor and Veslefrik. The increasing rate of decommissioning serves to emphasise that the present decade presents the best opportunity to roll out a CO_2 EOR infrastructure, extending field life and recovering hydrocarbons that otherwise would be abandoned, whilst securely storing CO_2 emissions away from the atmosphere. This same infrastructure (with its capital paid for during hydrocarbon production) could also be used beyond field life for dedicated CO_2 storage.

According to a joint announcement made by the energy ministers of Norway and UK at *Offshore Northern Seas* in Stavanger, in August, 2002, the cost of decommissioning oilfields up to 2010, alone, is estimated to be $3.3 billion. There is no off-setting revenue for this expenditure.

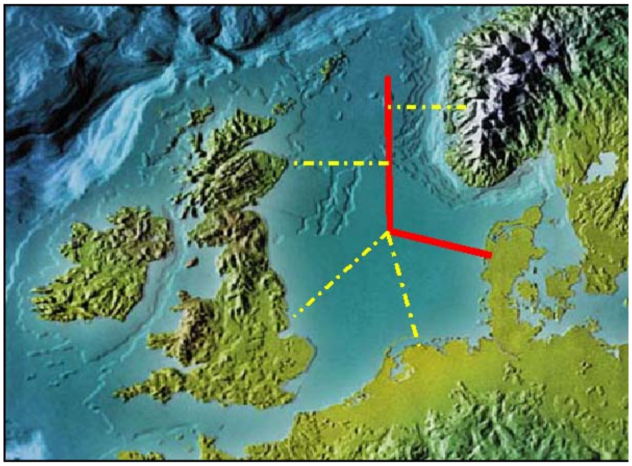
Other unwelcome consequences arising from the rapid fall of production include:

1. Dependence, after many years of being energy self-sufficient, on oil and gas from countries, some of which are notoriously unstable, all outside Europe, at a time when a growing number of industry experts foresee that World oil demand will be rising ahead of production.
2. Increased dependence on energy imports will raise balance of payment deficits, especially during periods of high energy prices.
3. Loss of many well paid jobs, as well as the need for oil towns like Aberdeen, Stavanger and Esbjerg to "re-invent" themselves.
4. Without tertiary recovery, the permanent loss of roughly half the unrecovered oil that is left in the ground, after decommissioning.

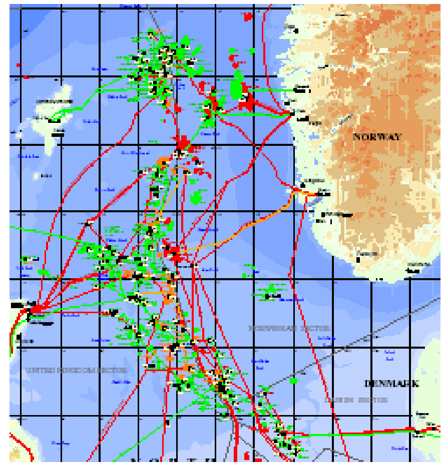
The "**C**O_2 for **E**OR in the **N**orth **S**ea" (CENS) project is the name given by its developers to an ambitious plan for bringing anthropogenic CO_2 from factories and power stations around the North Sea Basin to depleted oil fields, mainly in the UK, Norwegian and Danish sectors for enhanced oil recovery.

Virtually all the CO_2 used for enhanced oil recovery will be permanently sequestered.

3. Project Description



Diagrammatic representation of the proposed infrastructure as it might appear around 2007-14



Map, showing oil fields (green) in a relatively narrow corridor from 55° to 62° N

The technical and financial feasibility of the project relies, to some extent, upon the way in which most of the North Sea's oil reservoirs, coloured green on the map, are clustered.

A trunk pipeline up the Norway/UK median line would bisect important, mature, oilfield clusters from the south (Ekofisk and Fulmar) to the north (East Shetland Basin, called "Tampen" in Norwegian).

All the way, from the south to the north, there are many oilfields which are close to the median line, both west and east of the proposed trunk pipeline. There are also major oilfield "clusters", such as the Scapa and Brage/Oseberg clusters that can be accessed by large, branch pipelines.

There are few significant, stationary CO_2 sources in Norway. However, there are at least two which, further to confirmatory studies, could supply CO_2 competitively into the pipeline. Additionally, some large-scale, natural gas based, industrial projects are planned. These are mandated to be "CO_2 neutral". If these can be realised before the end of this decade, Norway could become a significant CO_2 supplier to the project, as well as a major beneficiary of the incremental oil.

There are many existing, large scale CO_2 sources in the UK and Denmark, of which some of the most important are accessible to the North Sea. Thus the developers have modelled two main feed lines, one from the west coast of Denmark and the other from the east coast of the UK. These would deliver most of the 30 – 40 million tonnes per year required for the recovery of 90 – 120 million incremental, "CO_2" barrels of oil per year.

Historically, the CO_2 received from a CO_2 infrastructure is used many times, as co-produced CO_2 is separated from the hydrocarbons, dried, liquefied and re-injected. The base case in the CENS project assumes that this will again be the case. Were this so, the sponsors are conservatively estimating that each tonne of freshly injected CO_2 will return 3.17 barrels of "CO_2" oil. This article refers to CO_2

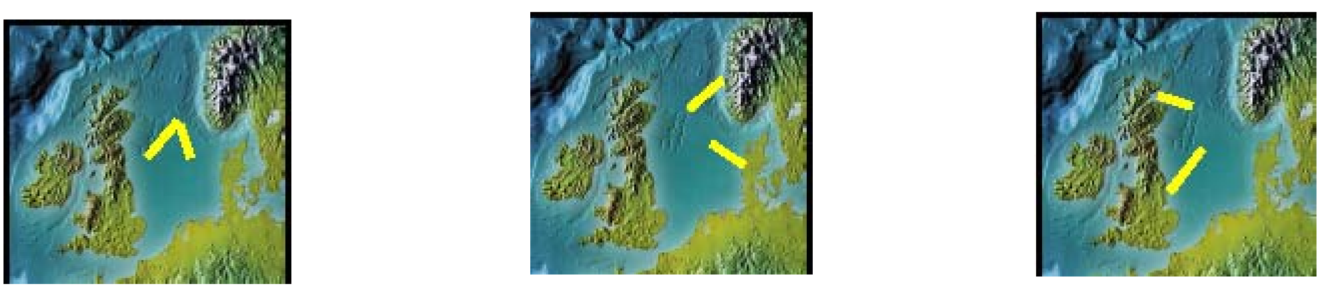
A CO2-membrane stripping unit (high-lighted) is attached to an offshore platform operated by *Unocal* in the Gulf of Thailand. The unit shown here is handling 1.8 mt CO2/yr.

brought to the oilfield and injected, as “fresh” CO_2. Current thinking is that once the residual oil has been extracted, the wells will be capped and the CO_2 permanently sequestered (as a value is expected to be placed on CO_2 left in the ground).

If the capacity of the infrastructure is sufficient and the legal issues are resolved, in some cases it might be more economical to simply dispose of CO_2-rich, break-through gas into deep aquifers for long-term storage rather than to separate the CO_2. This might occur in gas-lean reservoirs or at the end of EOR production when gas processing is expensive in relation to simple sequestration.

If sufficiently large CO_2 supply contracts can be signed at the early stages of the project, these might justify the construction of the south to north transport “spine” and the CO_2 supply feeders illustrated, diagramatically, at the beginning of this section.

If, on the other hand, the project is begun by supplying relatively few, small floods, the project could be started by the delivery of CO_2 by ship and developed by “joining floods” in a manner diagramatically illustrated by the following sketches.



There are different schemes for flooding a reservoir with CO_2. The optimal injection strategy will depend on the geological properties of each field, the physical properties of the oil, reservoir temperature and pressure, and how the field has been developed. The most widely used technology is to stabilize the CO_2 flood by alternating injection of CO_2 and water in the same well (WAG).

However, if the value of sequestered CO_2 is sufficient, there will be cases where gravity stable gas injection will be more profitable. In this case, there will be a delay in the appearance of incremental oil. On the other hand, the amount of incremental oil recovered will increase as will the amount of CO_2 which it is possible to sequester. A significant number of oilfields in the North Sea are technically suitable for this.

This has been studied already and written up in previous editions of this newsletter.
www.dti-sharp.co.uk/dissemination/openreports/UKCS_cap_paper_02.pdf)

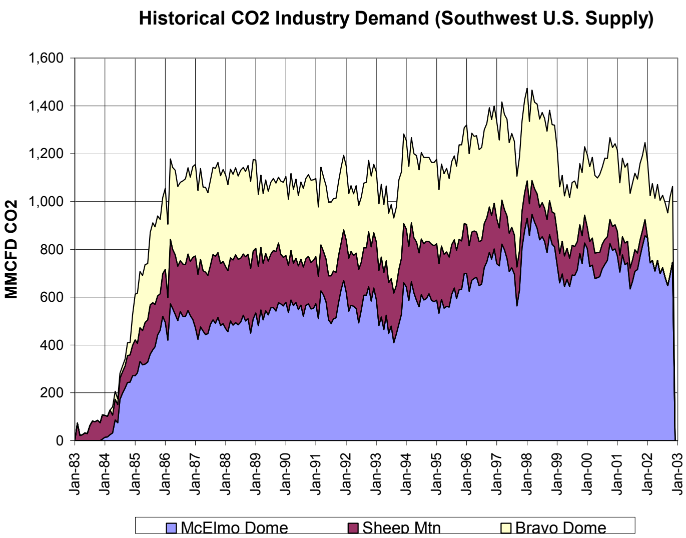
Comparison of the Permian Basin with the North Sea

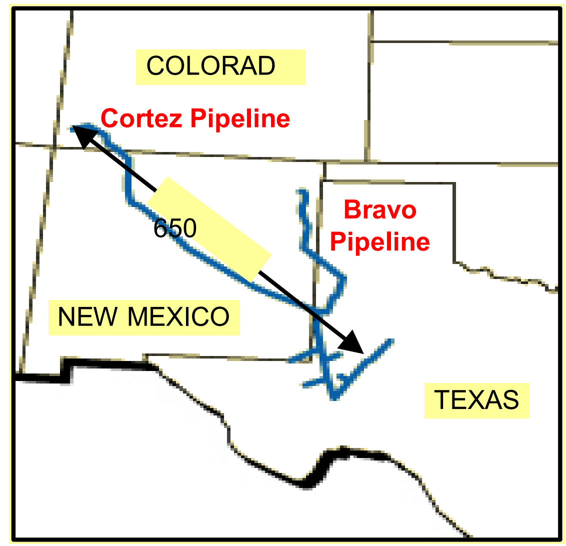
	Permian	**North Sea**
Temperature	Low geothermal gradient	High geothermal gradient (higher temperature at same depth below surface)
Rock Type	Predominantly carbonate	Mostly sandstone
Structure	Low dip angle beds	More steeply dipping beds
Well Productivity	Up to 3000 BFPD	Up to 20000 BFPD
Permeability	Low (<20 md)	High (usually > 500 md)
Residual Oil Saturation	20-30%	15 -40%
Stratigraphy	Pay zones generally not interrupted by faults, mostly stratigraphic traps	Fault block reservoirs
Most likely flood type	Horizontal Pattern flood	Gravity Stable
Operating cost structure	One of most inexpensive	One of most expensive
Well Spacing	Very dense (down to 10 acres)	Widely spaced
Crude quality	28-42 API sour & sweet	All grades from gas fields to black oil. Oil is predominantly sweet, high API gravity

4. Developers

The developers of the CENS project are:

- The Kinder Morgan CO2 Company (KMCO2) (http://www.kindermorgan.com/CO2)
- and ELSAM A/S (http://www.elsam.com).





KMCO2 owns and operates much of the 1,200 km CO_2 infrastructure which delivers around 22 million t per year of CO_2 to about 70 floods in the West Texas Permian Basin. The CO_2 is sourced from natural CO_2 domes in Colorado (the McElmo Dome) and the Bravo Dome in New Mexico.

Around 175,000 "CO_2" barrels per day are produced from this infrastructure in the Permian Basin.

On an historical note, KMCO2 is a successor to Shell CO_2 and inherited the large scale infrastructure which was built during the early 1970s under fiscal conditions reflecting anxieties about energy security which are relevant to those in Europe today. Additionally, in 1999, KMCO2 bought and now operates the giant SACROC oilfield, raising production from 8,000 barrels per day in 1999 to almost 16,000 barrels per day at the end of 2002.

KMCO2, as the World's largest and most experienced owner and operator of CO_2 infrastructure, brings a unique, practical perspective to the CENS project.

ELSAM A/S is the largest generator of electricity in Denmark. It owns six central power stations in West Denmark, all of which also deliver district heating to their local communities, giving a winter fuel utilisation of up to 93%. Of these, five are coal-fired and one gas fired. The two most recently built, are also the most thermally efficient, condensing, steam power plants in the World at 47% (LHV coal) and 49% (LHV gas).

ELSAM also owns 19 decentralised CHP plants and has just commissioned the first, large, offshore wind farm in the World, at 160 MW. ELSAM can deliver a peak electrical output of 3,500 MWe. In recent years, ELSAM's CO_2 emissions from its central power stations have been in the range 9.5 – 12 million tonnes/y. The concentration of CO_2 in the flue gas is typically 12 – 14%. This contrasts favourably with the flue gas from a combined cycle gas turbine plant where the concentration of CO_2 is in the range 3 – 4%.

All ELSAM's power plants are fitted with flue gas cleaning equipment to meet and exceed the requirements of the international authorities. Thus its plants are among the most suitable power plants anywhere for retrofitting conventional, amine scrubbers that will remove up to 93% of the CO_2 emitted. After retrofit, ELSAM's coal-fired units will emit environmentally harmless water vapour, nitrogen and only small quantities of CO_2.

5. CO_2 - Costs, Prices, Fiscal measures and the Value of Sequestration

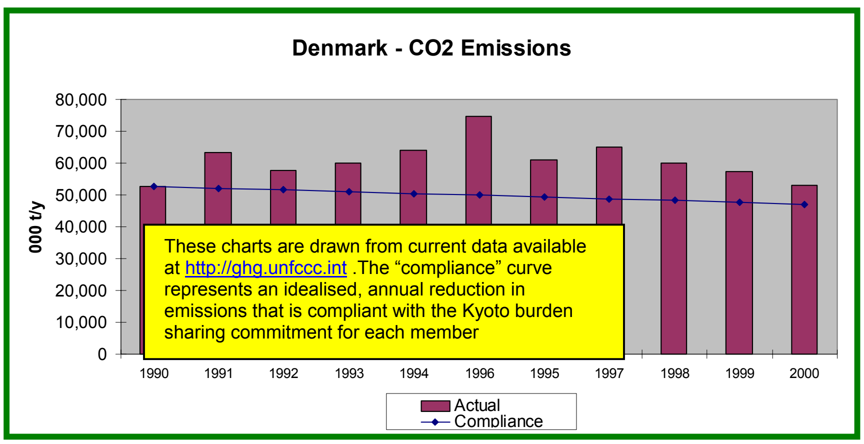
Extensive studies have been made by ELSAM to establish the cost and a commercially attractive selling price of dry, liquid CO_2 at the boundary of the power station such as the plant at Esbjerg, illustrated. These show the price of CO_2, leaving the power station boundary in Denmark, at somewhere between $23 and $25 per tonne.

These prices are similar to those estimated for certain UK sources.

KMCO2 has performed studies for various configurations of pipeline and transport. These show that the amortisation of the pipeline, its operation and the energy costs of transport add up to roughly $10 per tonne delivered at a "postage stamp" price. That is to say, the present, simplified postulate is that gas is delivered anywhere in the system at a single price. Thus, while the business develops, the CENS sponsors are quoting a delivery price at the platform of roughly $35/tonne CO_2.

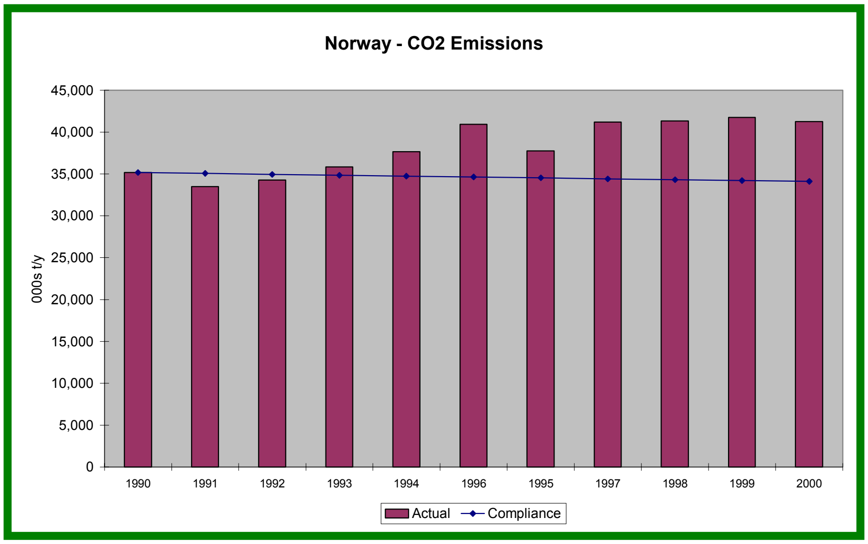
The current average price of CO_2 at oilfields in the Permian Basin is about $15/tonne. With a recovery rate of 3.3 barrels per tonne of "fresh" CO_2, the CO_2 cost of a "CO_2" barrel is $4.55. It should be noted that CO_2 at this price supports a thriving oil producing industry at a market price of $18/bbl oil. Higher prices for oil have recently increased demand for CO_2.

At $35 per tonne, the CO_2 cost to a producer in the North Sea of an incremental, "CO_2" barrel would be roughly $10.61. This cost would not leave enough to cover all the other costs of investment and production, using CO_2. However, the strong likelihood that buried carbon might have a higher value than the suppliers' price at the platform could result in disruption to traditional thinking.



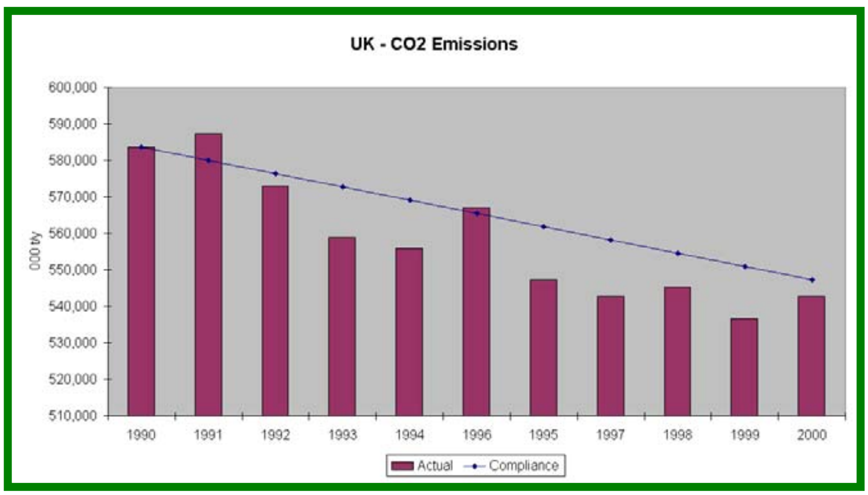
The developers have always recognised that if the gas cost is not offset by the value of its permanent removal from the atmosphere, the project would be unviable. Therefore, from the first, they have engaged in dialogue with the Governments of Denmark, Norway and the UK, all of which are aware of the CENS project and its possibilities.

These governments are engaged in a genuine effort to meet their exacting Kyoto commitments. Nevertheless, of the three, only the UK is currently "on track", although CO_2 emissions in the UK have now been rising for the last three years.



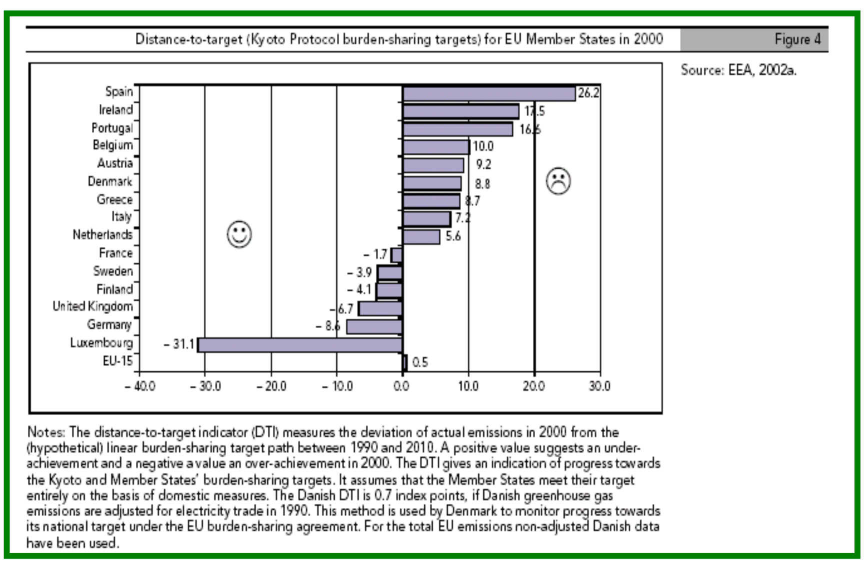
Denmark and Norway are out of compliance and have not yet announced any clearly defined path-way toward compliance.

Accordingly, the CENS project, with its potential ability to bury on average 30 – 40 million tonnes per year, which can start during the Kyoto 1 period and reaches apogee during the early years of Kyoto 2, should encourage these three governments, backed by the EU, to devise and implement fiscal measures which will make the project viable to all participants.



The conclusion of many experts is that the EU-15 will have great difficulty in collectively meeting its obligation for an 8% reduction in greenhouse gas emissions in a timely manner.

The EU-15 obligation amounts to a reduction of 336 million t/y CO_2 equivalent. Actual CO_2 emissions fell by just under 0.5% between 1990 and 2002, or just 17 million t/y. This is a massive 319 million t/y short of the target.



This table, from *"Greenhouse gas emission trends and projections in Europe"* summarises the progress – or lack of it.

Furthermore, it is the EU's intention that reductions during Kyoto 1 are just the beginning. By 2012, the EU-15 must be demonstrating larger and deeper cuts throughout "Kyoto 2". This will not be credible, if it struggles to meet the fairly modest targets set during Kyoto 1.

Therefore, in order for the EU 15 to achieve their Kyoto obligation, on time, and without economic pain, during the few years left to the end of Kyoto 1 (2010), many efforts using a variety of options will have to be made. There is no single "magic bullet".

These options will include further energy conservation in homes, offices and factories, more efficient transport, and alternative methods for space heating, industrial steam raising and electricity generation as well as increasing renewable energy generation.

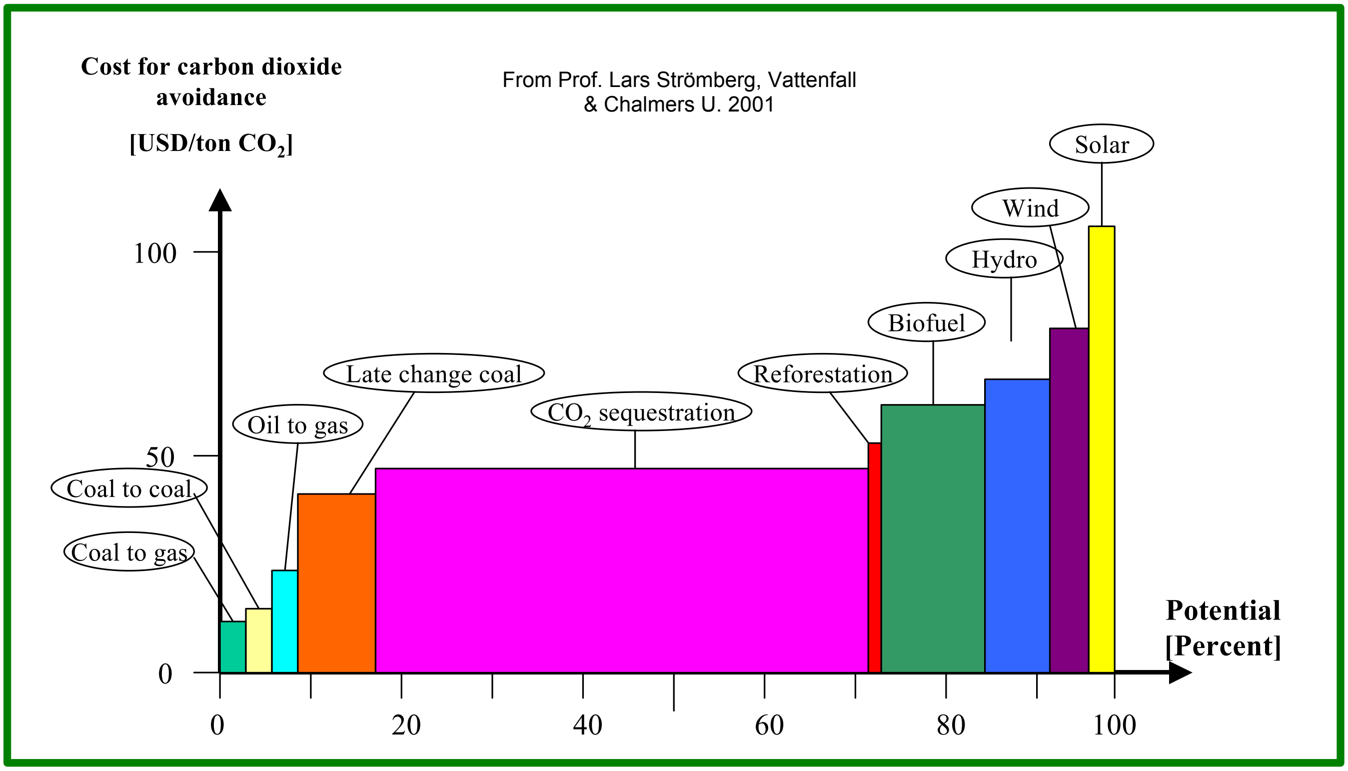
For the UK, any emission gains from its ambitious renewables targets could be offset by decommissioning of nuclear power plant. With the EU's ageing power plant infrastructure (e.g. by 2005 over 30% of electricity generating plants in the UK will be more 30 years old) the next 10 years offers an excellent opportunity to build new replacement plant more suited to CO_2 capture.

Of all the major sequestration projects presently mooted for Europe, only the CENS project appears to have the potential to return a "net profit". At a macro-economic level, the net income could exceed all capital and operating costs by a comfortable margin (with oil at $20/bbl and over). All this can be realised when there is a recognised value for sequestered CO_2.

This will require, at least, that the EU shall approve sequestration through EOR as an emission reduction measure, prior to 2005, in order to save many fields from decommissioning prior to 2010. If this happens, the newly passed EU directive on emissions trading would help create a value for sequestered CO_2 and could create a long term, contractual structure for emission credits. In turn, these contracts would enable CENS-like projects to raise sufficient project financing for implementation.

If the sequestered CO_2 attracts credits in the Euro 20 - 50 range, the oil operators could effectively enjoy "near free" delivery of CO_2 at the platforms.

Most industry estimates for the cost of CO_2 avoidance, including sequestration, easily exceed $35/t, as shown in the often quoted chart, reproduced below. In this, the Professor Strömberg estimates the approximate effects and costs that various CO_2 reduction measures will have for meeting the EU's Kyoto commitment, after the "low hanging fruit" of energy efficiency has been plucked. In the same chart, the costs of these various measures are roughly estimated.



Already, the Norwegian Government taxes oil operators in that sector at the rate of $35/t and at Sleipner has accepted underground injection of CO_2 as an emission avoidance option since 1996 (http://www.ieagreen.org.uk/ and www.statoil.com).

6. Fiscal Measures to Encourage Security of supply

EU energy projections (Green Paper on Energy and Security of Supply to 2020, http://europa.eu.int/comm/energy_transport/doc-principal/pubfinal_en.pdf) shows a significant, continuing dependence on fossil fuels against a backdrop of growing energy demand with approximately one third of emissions resulting from electricity generation.

So fiscal measures addressing security of supply could also play an important role in stimulating a CO_2 EOR infrastructure. Security of supply has several advantages.

(i) It increases non-OPEC production thus weakening OPEC's ability to dominate and swing the oil price.
(ii) Indigenous energy production has a positive effect on a EU's and national balance of payments and currency strength, especially during times of high oil prices.
(iii) It can help protect countries from interruptions of supply.

The USA has recognised the value of security of supply since the "Oil Crisis" in the early 1970's.. Measures brought in since then, especially the Crude Oil Windfall Profit Tax Act of 1980 greatly assisted the growth of CO_2 EOR in the USA and its associated infrastructure.

The legislation preferentially taxed some EOR project profits at 30 %, compared with a conventional crude oil profit tax of 70 % . Section 43 of the Internal Revenue Code provides taxpayers an enhanced oil recovery (EOR) credit equal to 15 % of their qualified EOR costs. Section 43 was a part of the Omnibus Budget Reconciliation Act of 1990, which made several changes to capital cost recovery methods. The Section 43 credit is phased out if oil prices rise above a certain level, i.e., $28 per barrel (in 1991 dollars) In order to be eligible for the credit, the taxpayer must employ certain tertiary recovery methods, such as miscible fluid replacement, carbonated water flooding, miscible floods and immiscible carbon dioxide replacement.

The UK government has recognised the need to support continued development and investment into mature N. Sea fields. In the Autumn Statement (2002) it announced that royalty payments will be abolished with effect from 1 January 2003. This decision recognises the important contribution that mature fields can make to the future of the North Sea and will deliver a significant boost to companies investing in these fields. The UK Government through the DTI's cleaner fossil fuels programme is presently conducting a review into the feasibility of CO_2 capture and storage in the UK, with CO_2 EOR being part of this review (http://www.dti.gov.uk/energy/coal/cct/co2capture.shtml)

The use of CO_2 for EOR is a proven industry practice for tertiary oilfield production. The use of anthropogenic CO_2 for EOR has the added benefit of reducing CO_2 emissions to the atmosphere. Mechanisms like CO_2 credit trading systems are being put in place that will help set a value for sequestered CO_2. Modification to other fiscal policies also may be necessary to encourage the introduction of this practice before the infrastructure of certain, old, large oilfields is decommissioned and remaining oil is left behind for ever.