Enhanced Oil Recovery using Carbon Dioxide in the European Energy System

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Sustainable Energy Technologies
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The objective of SETRIS is to collect, harmonise and validate information on sustainable energy technologies and perform related techno-economic assessments to establish, in collaboration with all relevant national partners, scientific and technical reference information required for the debate on a sustainable energy strategy in an enlarged EU, and in the context of global sustainable development.

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Executive Summary

Enhanced oil recovery using carbon dioxide (CO_2-EOR) is a method that can increase oil production beyond what is typically achievable using conventional recovery methods while facilitating the storage of carbon dioxide (CO_2) in the oil reservoir. In principle, when CO_2 is injected in an oil reservoir, it mobilises oil not extracted by conventional methods either by interacting physically and chemically with the oil and the reservoir rock, or by regulating the reservoir pressure. This results in an increased oil production. Hence, CO_2-EOR can help in the reduction of CO_2 emissions and simultaneously improve the security of energy supply. At present there are no applications of CO_2-EOR in Europe, only plans, although the technique has been commercialised elsewhere. In general, there are no major technical barriers for the implementation of such projects onshore. The most important issues that have hindered the implementation in Europe are the lack of availability of low cost CO_2 and the increased operating and capital expenses, especially when offshore projects are considered. These costs have made this type of oil production operations in Europe prohibitive under the oil-pricing regime of the near past.

However, the European energy scene is changing. The urgent need to curb CO_2 emissions in compliance with the Kyoto commitments and beyond makes CO_2 capture and storage technologies one of the carbon mitigation options worth considering. Furthermore, the emissions trading scheme is expected to provide some financial incentives for this decarbonisation option. At the same time, higher oil prices may now justify investment in oil recovery projects, which were previously deemed uneconomic.

These changes in the European energy market coincide with the approach to the cessation of operation of many oilfields in the North Sea. Soon, a decision needs to be taken to either abandon these oilfields and dismantle their infrastructure, or to keep them operating through investments in improved oil recovery methods.

This report assesses the potential role of CO_2-EOR in the European energy system. Initially, the report examines how CO_2-EOR may fit with the objectives of the European energy, energy research, and environmental policies. Next, the report reviews the current state of knowledge about CO_2-EOR, identifies potential barriers for implementation and highlights areas that require further research and development. Finally, the report estimates the potential for CO_2 storage and for additional oil production in the oilfields in the North Sea, as well as the associated costs. The region studied in this analysis is the most important oil-producing area in Europe, producing approximately 4 million barrels of oil daily, or 73% of crude oil produced in the European Economic Area (EEA).

81 active oilfields from the UK, the Norwegian and the Danish sectors of the North Sea were considered in the analysis, selected based on their reserves (higher than 73 million barrels). The maximum potential for additional oil recovery using CO_2-EOR was estimated for each oilfield, disregarding the economics. The average UK potential was estimated at 2.7 billion barrels (ranging between 1.8 and 3.7 billion barrels depending on the achievable oil recovery from each oil field), or 58% of the UK proven reserves in 2003. The average Norwegian potential was estimated at 4.2 billion barrels (40% of proven reserves), ranging between 2.8 and 5.7 billion barrels.

The Danish potential was estimated at 0.4 billion barrels (28% of reserves), ranging between 0.2 and 0.5 billion barrels.

The assessment indicates that the maximum potential for CO_2 storage in the oilfields of the North Sea may not prove significant when compared to the total GHG emissions in the EU, approximately 4 billion tonnes annually. The storage capacity of the oilfields in the UK and Norwegian sectors of the North Sea is approximately 1.8 and 3.1 billion tonnes of CO_2 (Gt) respectively when standard practices are applied. Standard practices imply the minimisation of CO_2 usage and the maximisation of CO_2 recovery after injection underground, to reduce the costs of the process, by reducing CO_2 purchases. If however, the storage of CO_2 had a commercial value, for example through emissions trading, CO_2-EOR operations could be designed to maximise the retention of CO_2 underground. In this case, the UK storage capacity could increase to approximately 3.5 Gt and that of Norway to 6.2 Gt.

Both the estimates for additional oil production and for potential CO_2 storage refer to a theoretical maximum potential. The actual potential in both cases will be limited by technology, the specific conditions for each reservoir, but most importantly by economics.

Fifteen oilfields, which are more than 80% depleted, were selected for a preliminary economic evaluation under high and low price scenarios for oil and carbon trading prices and under high and low oil recovery factors, as they may be dictated by the geological characteristics of individual oilfields. The location of the CO_2 sources was selected amongst existing coal-fired power stations, however the assumption is that new units with similar power generation capacity while capturing CO_2 will be built instead of retrofitting the existing power stations. Dedicated pipelines to each oilfield were considered for the transport of CO_2.

It was estimated that under favourable oil recovery factors (9% - 18% of additional oil recovery) and a low price scenario of 25$/bbl for oil and 15€/tonne of CO_2 stored through carbon trading, the implementation of CO_2-EOR could be economically viable in 9 of the 15 fields studied. These results are based on a 10% discount rate. Taxes and inflation have not been considered. Annual incremental oil production could reach 100 million barrels, while approximately 20 million tonnes (Mt) of CO_2 could be avoided annually for the 20-year project lifetime, when following standard practices. In a high price scenario of 35$/bbl for oil and 25€/tonne of CO_2, all oil fields studied could be profitable for CO_2-EOR operations. In the latter scenario, the annual incremental oil production could reach 180 million barrels and the yearly amount of CO_2 stored 60 Mt. These figures are reduced when lower oil recovery factors are considered (4%-10% of additional oil). In the high price scenario, 10 economically viable projects can produce 81 million barrels of oil annually, while storing 57 Mt of CO_2. These figures are reduced further in the low price scenario, where just 2 projects produce 19 million barrels of oil, while storing 3.7 Mt of CO_2.

However, uncertainty surrounding the eligibility for financial support (e.g. via emissions trading) with regards to EOR, along with high costs do not encourage investments in this technology. Furthermore, competition with other less risky improved oil recovery methods will have an impact on the role of this technique as a mitigation option for greenhouse gas emissions. Finally, environmental concerns for the permanence and safety of CO_2 storage underground and the unclear legal frame for CO_2 storage activities should not be overlooked.

In conclusion, CO_2-EOR could help Europe simultaneously reduce the emissions of CO_2, improve the security of energy supply by enhancing the recovery of European oil resources, and encourage the development, demonstration and deployment of advanced cleaner and more efficient fossil fuel energy conversion technologies by making available proven CO_2 storage sites. Our preliminary study indicates that at the oil prices of today and with a carbon-trading scheme, CO_2-EOR operations in the North Sea could be viable.

1 Rationale

Enhanced oil recovery (EOR) is a term used to describe a set of processes intended to increase the production of oil beyond what could normally be extracted when using conventional oil production techniques. While traditional oil production can recover up to 35-45% of the original oil in place (OOIP), the application of an EOR technique, typically performed towards what is normally perceived to be the end of the life of an oilfield, may produce an additional 5-15%.

One of these EOR techniques is based on the use of carbon dioxide (CO_2). The injection of CO_2 at high pressure into an oil reservoir can mobilize oil that has not been extracted using traditional methods. Furthermore, a fraction of the injected CO_2 remains stored underground, which is helpful in combating global climate change, since CO_2 is a greenhouse gas.

A limited number of oilfields are currently been exploited worldwide using the CO_2based EOR technique (called CO_2-EOR for short hereafter). The main barrier to the further implementation of the technique is the economics of CO_2 supply. The technique is currently implemented only in regions where CO_2 is available in large quantities and at a very low cost. In almost all of these cases, CO_2 originates from underground natural reservoirs.

There are no applications of CO_2-EOR in Europe as the economic situation has not been favourable for investment in such projects. The major barrier has been the availability of low cost CO_2 at the injection site. Given the absence of significant natural CO_2 resources in the proximity of the European oil-rich regions, large combustion plants, such as power stations, are potentially the only source. In a CO_2-EOR operation, the CO_2 generated in such combustion plants would have to be separated from the flue gases and transported to the oilfield for injection. The separation and capture of CO_2 from power stations has yet to be demonstrated commercially on a large scale. Furthermore, as the majority of the European oilfields are located offshore, at a significant distance even from coastal power stations, a CO_2 transport system would also have to be developed. The costs of CO_2 capture, transport and injection to the oilfield would add to the cost of oil production making such operations in Europe prohibitive under the oil-pricing regime of the near past.

However, the European energy scene is changing. The need to curb the emissions of CO_2 in compliance with the Kyoto commitments makes the capture and storage of CO_2 a carbon mitigation option, which is worth considering. Moreover, the emissions trading scheme is expected to provide some financial incentives for this. Higher oil prices may now justify investment in oil recovery operations deemed uneconomic in the past. Finally, the revitalization of the Lisbon strategy, which aims at making the European Union (EU) the most dynamic and competitive knowledge-based economy in the world by 2010, offers new opportunities for developing and deploying advanced energy conversion technologies based on the decarbonisation of fossil fuels.

This new situation has triggered an increasing interest in CO_2-EOR in Europe as well as the rest of the world (see for example the Communiqué from the 2005 G8 Summit that refers to CO_2-EOR opportunities). The implementation of such projects on a large scale can reduce the emissions of CO_2 providing also the means for safe underground storage sites. Simultaneously, they can improve the security of energy supply by

enhancing and prolonging the European oil production. In addition it can encourage the development, demonstration and deployment of new decarbonised fossil fuel energy conversion technologies. These technologies are needed for the transformation of our current energy system according to the needs of sustainable development. CO_2 emissions from plants will be reduced, at the same time making CO_2 reduction financially attractive.

The timing of these changes to the European energy market coincides with the approach to the cease of operation for many important oilfields in the North Sea. Hence, a decision will need to be taken soon on whether a number of oilfields will be abandoned completely with the oil recovery infrastructure dismantled. This will close the window of opportunity for further oil exploitation from these oil reservoirs.

The aim of this report is to assess the potential of CO_2-EOR in Europe. It is structured as follows:

- Initially the report examines how CO_2-EOR responds to the drivers of the European policies, namely the potential impact of CO_2-EOR on the European efforts to combat climate change, on the improvement of the security of energy supply and on the technology 'push' via the development and deployment of advanced energy conversion technologies. These issues respectively relate to environmental, energy, and research policies.
- The report then reviews the state of the art of the technology, identifies the main technological, legal and economic barriers to the implementation of CO_2-EOR in Europe, and indicates key areas that require further research and development.
- Finally the report presents a case study, a preliminary analysis for the implementation of CO_2-EOR in the North Sea, which is the most important oil-producing region in Europe, but whose output is recognised to be declining. The prospects for CO_2 storage and increased oil production in this oil-rich region are reviewed and the likely costs are estimated.

2 The Potential Impact of Enhanced Oil Recovery using Carbon Dioxide in Europe

2.1 Challenges for the European energy system

Affordable and plentiful energy underpins European life-styles and is an essential ingredient of economic prosperity. Yet, at the start of the 21st century, the EU, as the rest of the world, is confronted with the challenge of moving to a truly sustainable energy system. Among the most important issues that need to be addressed are:

- The reduction of greenhouse gas (GHG) emissions to combat global climate change.
- The improvement of the security of energy supply, necessitating the decrease of the reliance of the EU on external energy resources.
- The overcoming of obstacles to European economic growth and to the continuous improvement of competitiveness, which necessitates coping with high, volatile and uncertain energy prices, and with the increasing strain to world energy resources caused by the growing energy consumption in the developing world.

In response, the EU has taken a number of initiatives to address these issues, such as the ratification of the Kyoto Protocol, the European Climate Change Programme (ECCP), the Green Paper on the Security of Energy Supply [1], to name a few. The extrapolation of present trends, however, indicates that current measures may not be sufficient to help Europe reach its goals. To this end, the EU has recently launched a number of important policy initiatives aiming at (i) minimising the impact of the energy sector on the environment (ii) securing the energy supply, and (iii) improving the competitiveness of the European energy industry.

There are policy measures that directly address these major issues. These include the introduction of alternative fuels for the road transport sector, trading of CO_2 emissions, effective energy demand management, the improvement in the efficiency of the power generation sector (including the promotion of cogeneration of heat and power), and the promotion of the use of renewable energy sources (RES). There are in addition 'frame' concepts that offer the potential to radically transform and significantly improve the sustainability of our energy system. The EU is supporting, facilitating and wherever appropriate leading initiatives towards the *hydrogen oriented economy*, i.e. the use of hydrogen as energy carrier for the future together with electricity. The European Vision for the Hydrogen Economy, a Strategic Research Agenda and a Deployment Strategy have already been prepared and a Technology Platform is currently at work, aiming at accelerating the development and deployment of key hydrogen technologies in Europe. Another initiative, still at the concept stage, is the *Zero Emissions Fossil Fuel Power Plant*. There is little doubt that fossil fuels will remain the main source for energy in the foreseeable future. Hence, there is a need for a compromise between the continual usage of fossil fuels and environmental protection. As such, this power plant concept will involve the separation of carbon from the fossil fuels as CO_2, which will be subsequently stored permanently and safely in suitable underground sites. To this end, the European Commission recently invited relevant stakeholders in formulating an industry-led Technology Platform, which aims at identifying and removing the obstacles to the

creation of highly efficient power plants with near-zero emissions which will drastically reduce the environmental impact of fossil fuel use, particularly coal.

A common element in both concepts, hydrogen and the zero emissions fossil fuel power plant, is the need to capture CO_2 and store it safely and permanently. The potential benefits for the power sector are very significant. Carbon capture and storage technologies can allow the power sector to minimise its GHG emissions while exploiting indigenous as well as imported low cost coal. Furthermore, it is widely accepted that the coupling of hydrogen production technologies that use fossil fuels as feedstock with carbon capture and storage technologies are important for the entry of hydrogen in the energy market, even in the long term, since fossil fuels are the most readily available and currently the most cost effective source for hydrogen. Furthermore, the conversion of fossil fuels to hydrogen relies on mature technologies.

Carbon capture and storage technologies have been assessed in detail in a previous JRC report [2]. That report concluded that there is now a good understanding concerning the underlying science of the technology for carbon capture and storage from large combustion plants. Nevertheless, due to limited experience with validation and demonstration, the deployment of carbon capture and storage technologies is still considered a technological and scientific challenge, as well as a financial burden. Although a number of technologies have been proposed and some of them already used for the capture of CO_2 albeit on a small and medium scale, developments are still needed for their use in power plants[1]. A CO_2-transport network needs to be constructed from the location of capture to that of storage or utilisation; and environmentally acceptable, safe, verifiable, publicly approved and economically viable storage options need to be provided in accordance with international treaties and national legislation. To this end, the EU has been supporting related research activities in the context of the multi-annual research, development and demonstration framework programmes (FP5 and FP6).

G*eological storage* is currently considered as the best carbon sequestration option. Carbon dioxide can be stored in suitable geological formations, such as active (using EOR) and depleted oil and gas reservoirs and deep saline aquifers. The major issue associated with geological storage is the assessment of storage capacity and the estimation of retention times. Although CO_2 is not toxic, its release may cause asphyxiation, contaminate drinking water supplies and, on a global scale, may make carbon capture and storage an ineffective strategy for reducing GHG emissions. Currently, there is one commercial application of geological CO_2 storage worldwide — the Sleipner Project, where one million tonnes of CO_2 (Mt CO_2) per year (the equivalent of the emissions of a 140 MW power plant) are injected and stored in a saline aquifer in the North Sea. Furthermore, CO_2 injection underground in a gas field has commenced recently in In-Salah (Algeria) and plans have been finalised for a similar project in the Snohvit gas field in the Norwegian Sea.

[1] Currently, 5.7 million tonnes of CO_2 are captured from 6 chemical and gas treating plants for EOR use. The largest of them is the Dakota Gasification Plant in the USA, which captures around 1.75 million tonnes of CO_2 annually, used for EOR in the Weyburn project in Canada. Two other gas processing plants in the USA supply each 1.2 million tonnes annually to the Rangely and Shanon Ridge EOR fields [3].

A critical factor that may dictate whether or not carbon capture and storage will be deployed in Europe is economics. Carbon capture from power plants and storage underground is costly and can only be justified through direct financial support or some type of taxation regime, such as CO_2 credits. However, the expectation is that the resulting additional charge to the cost of electricity and hydrogen [4] can be justified in the context of sustainable growth.

While the economics of carbon capture and storage continue to be debated, CO_2-EOR appears to be a financially viable CO_2 storage solution worth considering in oil producing regions. The fundamental principle of the technique is simple: Carbon dioxide captured from power plants or other anthropogenic CO_2 sources is injected into oilfields that have nearly reached their end of life, at the end of the application of traditional oil recovery techniques, helping additional oil to come to surface. As a result of this process, CO_2 is stored underground, while additional oil is produced, hence creating an income that helps the overall economics of the process. Furthermore, additional revenue could be earned through CO_2 credits or other financial support. This technique is being practised since the 1980s, however on a small scale.

2.2 EOR-CO_2 and the increase of the European oil production

2.2.1 Current status of oil production and consumption in Europe

Based on the latest information available from EUROSTAT [5] at the time of writing of this report, crude oil production in EU25 reached approximately 1.05 billion barrels in 2003, which corresponded to 4.0% of world oil production. The gross inland consumption of oil in EU25 that year was approx. 4.78 billion barrels. Hence, 78% of the oil consumption in EU 25 in 2003 was met by imports, mostly from the OPEC countries (40.3%), followed by Russia (24.8%) and Norway (22.0%) [6]. Historical data show that such a high level of dependency has persisted at least for the past 15 years (see Figure 2.1).

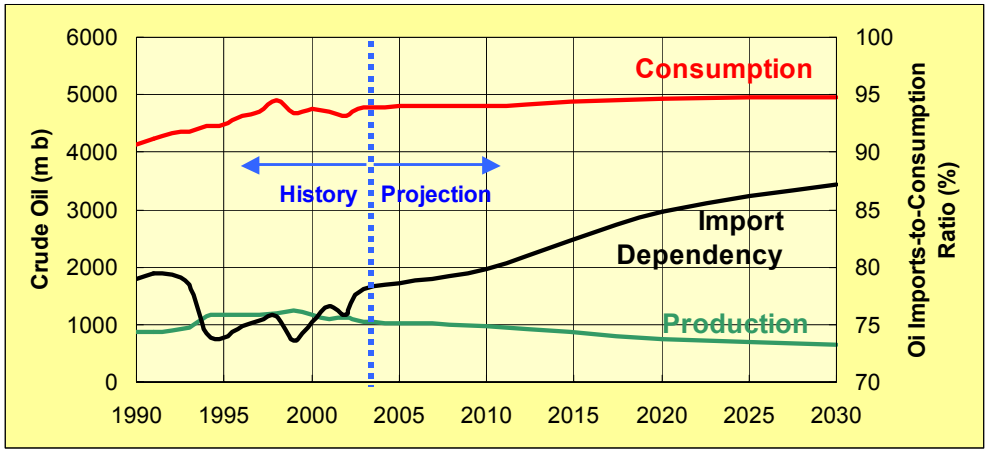

Figure 2.1: Crude oil production, net gross consumption and import dependency in EU25 during the period 1990-2030. Historical data taken from [5] and projections from [7].

Various studies, such as [7, 8], have estimated that this dependency will increase steadily in the future. European oil production is predicted to decline at an annual rate of 2.1% on average during the period to 2030, while oil consumption will continue to increase, although slowly, at a rate of 0.2%. Overall, the dependency of the EU25 on oil imports will gradually rise to 87% in 2030 (Figure 2.1).

The UK is the most important oil producer in the EU25. The UK production in 2002 accounted for 76% of oil production within the EU25 [9], followed by Denmark (12%), Italy (3.6%), Germany (2.3%) and the Netherlands (2.0%). The Czech Republic, Greece, Spain, France, Lithuania, Hungary, Austria, Poland, Slovenia and Slovakia did produce some oil, however their aggregated production was 3.9% of the total in the EU25. The remaining countries did not report any oil production in 2002.

Norway is the largest oil producer in Western Europe. Being a member of the European Economic Area (EEA), Norway is the most technically-linked state among all others associated with the EU[2]; this is advantageous for the EU oil supply. The Norwegian oil production in 2003 was 2.85 million barrels per day (mb/d), while that of the UK was 2.4 mb/d. To put these figures in perspective, the daily production in the USA, Russia and Saudi Arabia that same year was 5.7, 9.8 and 8.4 mb/d respectively [10]. Historical data show that oil production in EEA (EU25 and Norway) peaked in 1997 (6.2 mb/d) and has been in decline thereafter (Figure 2.2).

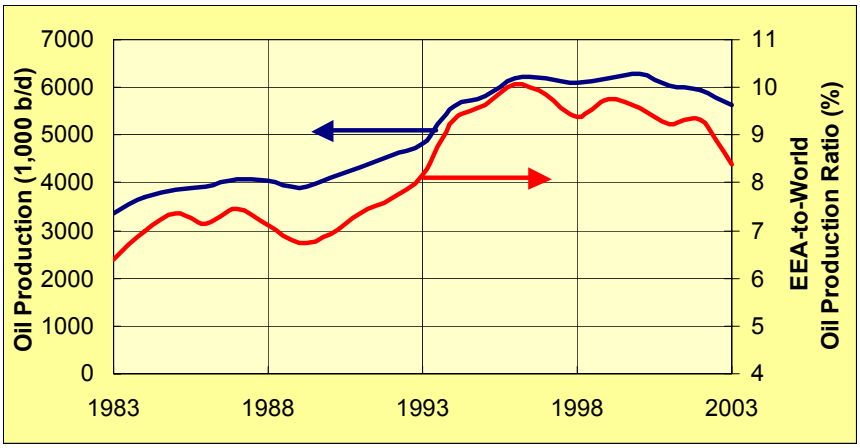

Figure 2.2: Historical data for oil production in the EEA [10]

Although the European crude oil production is in decline, the proven crude oil reserves[3] have remained nearly stable during the last 15 years, due to the continuous discovery of new fields, mainly in the North Sea region. The EU25 reserves have been on average 7.9 billion barrels during the period 1999-2003 and those of EEA 18.4 billion barrels. The available data show that the EEA oil reserves account for

[2] Together with the other two EFTA members, Iceland and Liechtenstein.

[3] Proven reserves are defined as '*an estimated quantity … statistically defined as crude oil,… which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions'*. [10]

about 1.6% of world oil reserves (Figure 2.3). More than half of the EEA reserves belong to Norway (58%), 25% to the UK, 7% to Denmark, 3% to Italy and the remaining 7% to other EU countries.

The reserve-to-production ratio of the oilfields in the EEA States, an indicator that is used to characterise the time in years before oil is depleted, has dropped from 18 years in 1983 to 9 years in 2003. The reserve-to production ratio was 6.2 years for the UK and 10.0 years for Norway in 2003 (Figure 2.4). The corresponding aggregated reserve-to-production ratio worldwide in 2003 was 46 years and that of the OPEC countries 91 years. These values indicate that although there are significant oil resources worldwide to meet the demand for the near and medium term, Europe's oil resources are on the way to depletion. As such, Europe's dependency on oil imports will continue to rise.

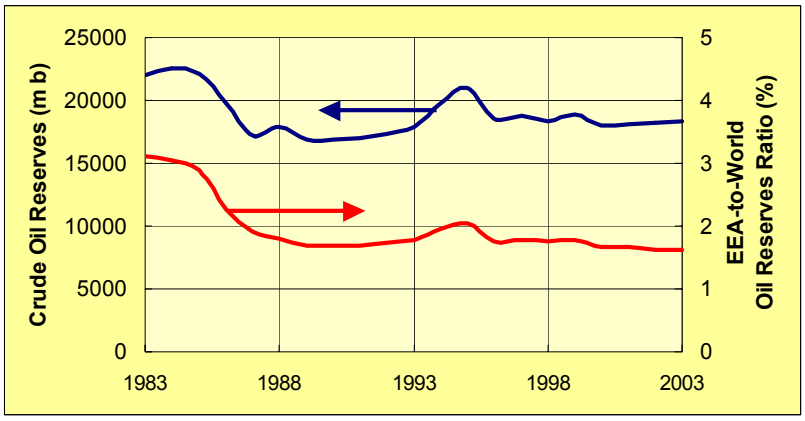

Figure 2.3: Historical data for proven crude oil reserves in the EEA States [10]

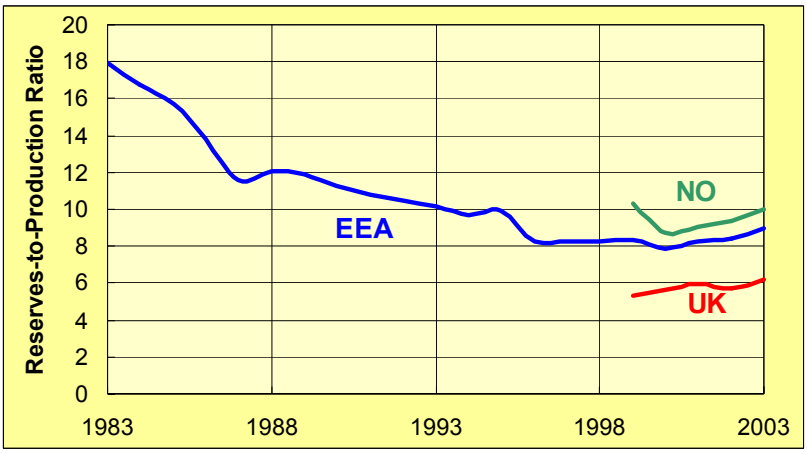

Figure 2.4: Historical data for the reserves-to-production ratio in the EEA, Norway (NO) and the UK [10]

2.2.2 The impact of CO_2—EOR on the European oil production

Experience from US operations has demonstrated that the use of CO_2-EOR can increase oil recovery by 9% to 18% beyond what is achievable when using conventional recovery methods. The exact increased recovery fraction depends on the injection method used and the characteristics of each oil reservoir and crude oil it contains. These issues are discussed in detail in the following Chapter.

A case study was performed by the JRC aimed at assessing the additional amount of oil that could be produced by implementing CO_2-EOR techniques in the oilfields of the core area of the North Sea, within the UK, Norwegian and the Danish sectors (Figure 2.5). Oilfields in areas west of Shetland and in the Norwegian Sea were not included in the study. The area studied is the most important oil-producing region in Europe, as it produces approximately 4 million barrels of oil daily, or 73% crude oil produced within the EEA. This assessment is presented in Chapter 4.

Figure 2.5: Map of Europe. The area under consideration in the case study is indicated in red.

In summary, 81 active oilfields were considered in the analysis, selected based on their reserves (higher than 10 million tonnes - 73 million barrels). 46 of them are in the UK sector of the North Sea, 30 in the Norwegian sector, and 5 in the Danish sector. These oilfields were grouped into 3 categories: (i) those suitable for *miscible* CO_2-EOR operations that offer an engineering potential for additional oil recovery

within the range 4% - 9% (59 fields), (ii) those suitable for *immiscible* CO_2-EOR operations that offer the potential for an additional 10% - 18% of oil recovery (16 fields) and (ii) those unsuitable for CO_2-EOR (6 oil fields). The criteria for forming these groups of oilfields and selecting these additional oil recovery factors are described in detail in the next Chapter.

The potential range for additional oil production using CO_2-EOR, disregarding economic considerations, was estimated for each oilfield by multiplying the estimated original oil in place (OOIP) with the upper and lower recovery factors stated above. The UK potential was estimated to be on average 2.7 billion barrels (ranging between 1.8 and 3.7 billion barrels, or 38% to 75% of the UK proven reserves in 2003). The Norwegian potential was estimated as 4.2 billion barrels (ranging between 2.8 and 5.7 billion barrels or 27% and 54% of proven reserves). The Danish potential was estimated as approximately 0.36 billion barrels (ranging between 0.22 and 0.50 billion barrels or 17% to 39% of reserves). The results are summarised in Figure 2.6.

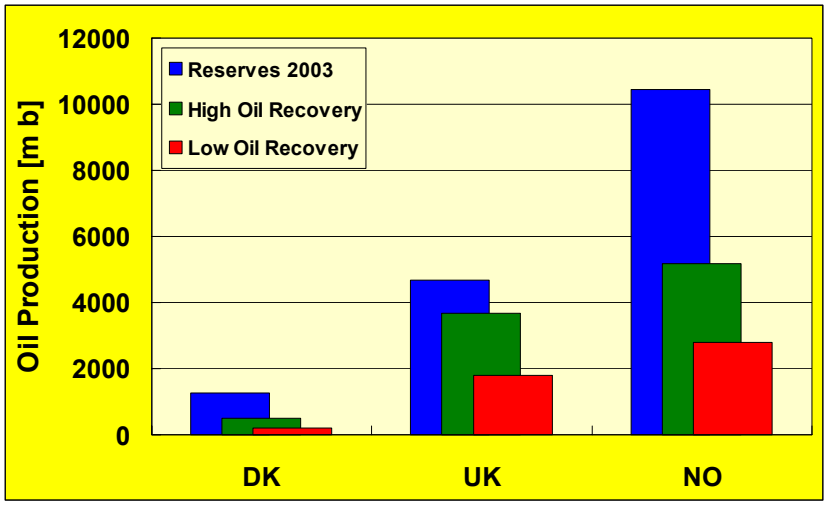

Figure 2.6: Estimated maximum potential for additional oil production by applying CO_2-EOR techniques in the UK, Norwegian and Danish oil fields of the North Sea under different assumptions for oil recovery rates.

On the basis of current knowledge, these estimates represent a ceiling of what could be recovered. The actual potential for additional oil recovery will be limited by technology (while significant experience has been gained for miscible CO_2-EOR projects, very little is currently known about immiscible operations), the specific conditions for each reservoir, but more importantly by economics. Competition with other improved recovery techniques and exploitation of satellite fields [11] may reduce the CO_2-EOR potential. The preliminary assessment by the JRC indicates that 20 to 180 million barrels of oil could be produced on an annual basis, in the near term, from a number of economically viable projects, depending on the actual oil recovery factors achieved in each EOR project and the price of oil and of the certificates in emissions trading for CO_2. This corresponds to an increase of up to 5-10% in UK and Norwegian annual oil production compared to the 2003 production levels.

Furthermore, the implementation of CO_2-EOR may have an additional indirect effect in increasing oil production. The prolongation of the operation of oil recovery infrastructure may enable additional oil to be recovered from satellite fields explored simultaneously with CO_2-EOR projects. Furthermore, new technologies may be developed while CO_2-EOR projects are managed, permitting the further exploitation of existing oil reservoirs.

2.3 EOR-CO_2 and the reduction of GHG emissions in Europe

2.3.1 Greenhouse gas emissions from the European energy sector

The energy industry is among the worst polluting sectors of the European economy, the reason being the heavy dependence of energy production and use on fossil fuels. On a regional/local level, the fossil fuel-based energy industry is responsible for air, water and soil pollution. However, the level of pollution from the energy sector at a regional scale has been effectively controlled with the establishment of proper legislative measures coupled with the use of technology. Legislative measures include the *Large Combustion Plant Directive* [12] that sets limits to the emissions of pollutants from combustion installations, including thermal power plants; the *Waste Incineration Directive* [13] that limits emissions from waste incineration plants; and the *Integrated Pollution Prevention and Control (IPPC) Directive* [14] that dictates the use of best available techniques (BAT) to combat pollution[4], to name a few. Recently, the *6th Environmental Action Plan* has taken a wide-ranging approach to the challenge of improving further the environment [15]. The effectiveness of these measures sets a clear example on how technology can successfully support environmental legislation.

Yet, the impact of the energy sector on the environment has another dimension on a global scale, namely climate change. The dominant anthropogenic gas that causes global warming is CO_2, and the energy production and use sector is responsible for more than 85% of its total emissions [16].

Due to the global scale of the climate change issue and the potentially devastating effects of global warming to sustainable development, political discussions have taken place for the last decade under the auspices of the United Nations Framework Convention on Climate Change (UNFCCC). UNFCCC produced in 1997 the Kyoto Protocol[5], a legal agreement among the developed countries to limit their GHG emissions by at least 5% below the 1990 levels, by 2008-2012. The EU being at the forefront of the International Community to combat climate change has committed to cut its emissions by 8% [6].

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[4] The European IPPC Bureau (EIPPCB - http://eippcb.jrc.es/) has been formed to catalyse an exchange of technical information on BATs under the IPPC Directive and to create best reference documents (BREFs) that inform about what may be technically and economically available to industry in order to improve environmental performance. These BREFs must be taken into account before a permit is granted to an installation.

[5] For the full text of the Protocol see: http://unfccc.int/resource/docs/convkp/kpeng.html

[6] Under a "Burden Sharing" Agreement each member state of the EU has a different emissions reduction target.

To this date, the EU has been able to reduce the emissions of GHG gases by 3% below the 1990 level (Figure 2.7) to 4123 Mt (in CO_2 equivalents) [17][7]. The energy sector (that includes power generation, petroleum refining, fuel processing, transport, energy use, mining, natural gas processing, etc.) has been responsible for 81% of GHG emissions, mainly of CO_2. Power generation and heat production are the largest CO_2 emitters of the energy sector, being responsible for 29% of the GHG emissions in the EU, followed by road transport (23%), manufacturing industries and construction (17%).

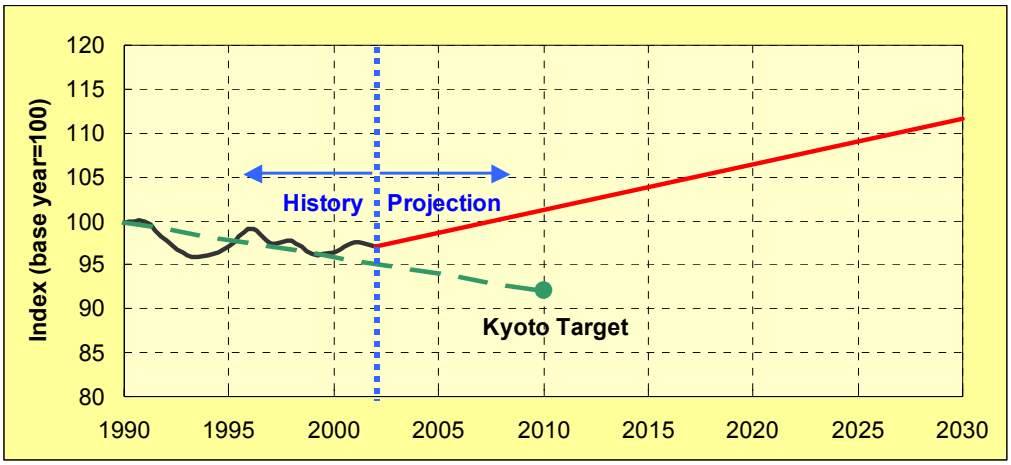

Figure 2.7: GHG emissions in EU during the period 1990-2002 (black line) [17] and projected evolution during the period to 2030 based on a BAU scenario (red line) [7]. The linear dashed line (in green) provides a measure of how close the EU emissions are to the Kyoto target.

Energy outlooks indicate that based on a business-as-usual (BAU) scenario, the CO_2 emissions in EU25 would increase reaching the 1990 level in 2010 and exceed it by 14% in 2030 (Figure 2.7) [7].

While the Kyoto Protocol has come into force, discussions in the International Community now focus on mid- and long-term climate strategies and targets beyond Kyoto. The EU Council of Ministers stated in 1996 that '*global average temperatures should not exceed 2°C above pre-industrial levels*'[8]. Significant cuts in GHG emissions on a global scale would be required to reach this goal. To facilitate the ongoing discussions, the European Commission undertook a 'cost-benefit' analysis taking into account environmental and competitiveness considerations. Based on the results of this study a number of key elements were recommended that should be included in the future EU climate change strategy, as proposed in a recent Communication from the Commission on global climate change [18]. Among these, enhanced technology innovation is cited. It is further stated that '*the Commission will review progress and explore new actions to systematically exploit cost effective*

[7] This value does not account for land-use change and forestry (LUCF) sinks.

[8] 1939th Council Meeting, Luxembourg, 25 June 1996.

emission reduction options in synergy with the Lisbon strategy'. To this end, carbon capture and storage have been identified as technology options, which should receive special attention. In response to this, a dedicated Working Group has recently been formed in the frame of the second phase of the European Climate Change Programme (ECCP II).

2.3.2 CO_2—EOR and the reduction of CO_2 emissions from the European power sector

Oilfields are proven fluid traps, providing some assurance that any injected CO_2 would be stored for a long period of time, sufficient to be considered as a reasonable CO_2 storage option to combat climate change. Furthermore, the geology and the properties of oilfields are better characterised than other non-commercially explored geological storage options, such as aquifers. Significant data have also been collected during oil extraction, which have established an important knowledge-base. Hence, CO_2-EOR projects could be the forerunners for the development, deployment and validation of other geological storage techniques. The cost of developing CO_2-EOR projects could be offset by the income from the additional oil produced. In addition, the experience with EOR could be of direct benefit when Europe moves away from the use of CO_2 as a medium for oil recovery to simple capture from power plants and subsequent storage in disused oil and gas fields. EOR experience would reduce both costs and development times for simple CO_2 storage.

Experience from CO_2-EOR projects in the USA shows that on average 0.33 tonnes of CO_2 are required to produce an incremental barrel of oil in miscible EOR operations; this value could increase to 0.8 –1.1 tonnes per barrel of oil for immiscible CO_2-EOR. Accordingly, the current assessment indicates that the maximum potential for CO_2 storage in the oil fields of the North Sea may not be very significant. The total storage capacity of the oilfields in the UK sector of the North Sea, when standard practices are used, is approximately 1600 to 2000 Mt CO_2, depending on the achieved oil recovery factor. The storage potential in the Norwegian sector is larger, estimated as 2900 to 3400 Mt (Figure 2.8). To put these figures in perspective, the GHG emissions of the electricity and heat production sector in the UK in 2002 was 157.6 Mt and the total GHG emissions in the EU in 2003 were approximately 4 Gt. Hence, the storage capacity of the UK oilfields in the North Sea is theoretically sufficient for half of the GHG emissions produced in EU in a single year, or all GHG emissions of the UK power sector for approximately 13 years. The corresponding figure for Denmark is almost 7 years.

The above-mentioned estimates of maximum storage capacity are based on the assumption that typical CO_2-EOR operation practices are followed. As explained next in the report, standard practices imply the minimisation of CO_2 usage through its recovery after injection to the greatest possible extent, to minimise the cost of CO_2 supply. If however, the storage of CO_2 had a commercial value, for example through emissions trading, the CO_2-EOR operations could be designed to maximise the retention of CO_2 underground by continuing the injection of CO_2 even after the termination of the EOR project for storage purposes. In this case, the amount of CO_2 stored in miscible CO_2-EOR operations would be higher than that considered with the application of normal practice. The UK storage capacity could increase to approximately 3500 Mt, or 22 years of storage of the UK emissions from the power

sector, the Danish capacity to 456 Mt, or 19 years of storage of the Danish emissions, and the Norwegian capacity to 6160 Mt.

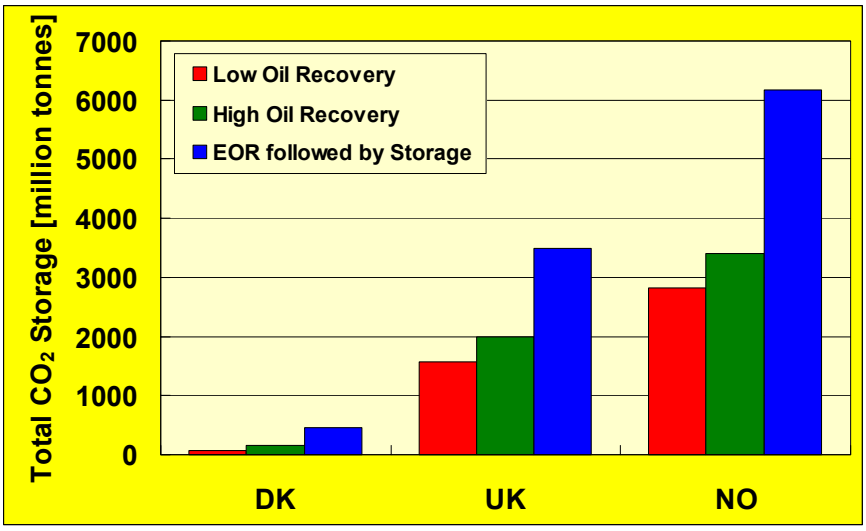

Figure 2.8: Estimated maximum potential for CO_2 storage capacity using CO_2-EOR in the oil fields in the North Sea under three different scenarios.

Clearly, these are theoretical maximum capacities. The actual potential will be dictated by technology and economics. Our assessment below indicates that between 4 and 62 Mt of CO_2 could be stored annually in selected economically viable projects in the near term.

2.4 CO_2-EOR and the competitiveness of the European economy

2.4.1 The energy sector and the competitiveness of the European economy

In the context of the Lisbon strategy that aims at revitalising the European economy, competitiveness has been identified as one of the pillars of sustainable development, together with environmental protection and social cohesion. The energy sector does play a dominant role in the efforts of Europe to improve its competitiveness. Low energy and fuel prices, an uninterrupted energy supply, and environmentally compatible energy generation and usage technologies are a prerequisite for a sustainable growing economy. High and volatile energy prices, as are typical for the first half decade of the 21st century, will however hinder economic growth in Europe. Furthermore the recognition that fossil fuels will remain at the core of the European energy system for the near and medium term reinforces the need for minimising the impact of the energy sector to the environment as well as any risks associated with the supply of fossil fuel resources.

These issues have now motivated the European Union to better link energy, environment and research policies. The promotion of an energy policy, which contributes at the same time to the Lisbon and Kyoto objectives, has now become a key objective for the European Union. This in turn requires the development and

introduction of new technologies, which enables the transformation of Europe's commitment to environmental protection into a competitive advantage. In support of this approach, investment in a programme that promotes more efficient and cleaner fossil fuel energy conversion technologies could create a significant market opportunity in the short and medium term. Europe is currently among the world leaders in energy technologies and energy services. Further investment in advanced decarbonised fossil fuel technologies could strengthen Europe's position in the global market, boost employment in high-quality jobs and assist developing countries to meeting their energy needs using sustainable energy technologies developed in Europe, offering them the means to reduce their own GHG emissions. The market potential is significant, as the electricity industry needs to expand and modernise in the coming decades. In Europe alone, 650 GW of new capacity needs to be built to meet the rising electricity demand and to replace 330 GW of aging power stations by 2030. The corresponding investment cost is approx. €500 billion [19]. This cost is increased to €1.2 trillion in the Communication of the Commission [18]. Furthermore, given the long lifespan of power plants, any decisions on power generation options will affect GHG emissions for many decades.

2.4.2 The impact of CO_2—EOR on the competitiveness of the European power industry

As mentioned above, CO_2-EOR projects can catalyse the development and deployment of carbon storage projects by reducing the associated costs and development times. These in turn can lead to the development of technologies that decarbonise fossil fuels and produce electricity and/or hydrogen on a large scale while eliminating CO_2 through cost effective capture and safe storage. These technologies will ultimately pave the ground for a renewable economy that uses electricity and hydrogen as energy carriers. Examples of these technologies are the zero emissions fossil fuel power plant and the HYPOGEN facility. HYPOGEN is one of the projects proposed in the Quick-Start Programme of the European Initiative for Growth [20]. This project refers to the development of a large-scale test facility for the co-production of power and hydrogen. Fossil fuels are the natural choice of fuel for this facility. In this context, CO_2-EOR has been recognised as an important option for the design of such a facility as it can improve the economics of the project and can offer an additional incentive to attract private funding [21]. The development of technology that can produce electricity and/or hydrogen from decarbonised fossil fuels may give Europe a competitive edge in the global energy market.

3 A Review of the Enhanced Oil Recovery Technique using Carbon Dioxide

This Chapter summarises the fundamental principles of CO_2-EOR and the current state of knowledge and experience concerning the technique. Moreover it identifies technological and other barriers to implementation in Europe and suggests key areas that require further research and development.

3.1 Petroleum Basics

Petroleum[9] or *crude oil* is defined as a mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure [10]. In addition to carbon and hydrogen, crude oil may also contain small amounts of oxygen, nitrogen, sulphur and traces of metals. The chemical composition of crude oil may vary between 83-87% carbon, 11-16% hydrogen, 0-7% oxygen and nitrogen combined, and up to 4% sulphur, depending on the oilfield. The composition of crude oil determines the fraction of low hydrocarbons, which are the most useful compounds for the production of liquid fuels for transport. Furthermore, the composition influences the physical and chemical properties of crude oil, including the specific gravity[10] and viscosity[11], that in turn affect oil extraction processes, as discussed below. Typical properties of crude oils are shown in Appendix I.

Petroleum is formed in deep geologic formations called *source rocks*. Upon their formation, the hydrocarbon species that constitute the crude oil migrate upwards, through porous geologic strata. The crude oil either reaches the surface, or is accumulated underground when its upward migration is confined by an impermeable rock, called the *cap rock.* The geological 'trap' formed by the cap rock is known as the *oil reservoir* (see Figure 3.1). The oil that is contained beneath the cap rock is in the *reservoir rock*, which is a porous and permeable geological formation that has the capacity to store and transmit fluids. Typically, the pores between the grains of the reservoir rock form an interconnected network that gives the rock its storage space and its permeability[12].

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[9] The term *petroleum* originates from the Greek words '*petra*' for rock, and '*eleon*' for 'oil'.

[10] Specific gravity is the ratio of the density of the crude oil to the density of water. Specific gravity is expressed on the API (American Petroleum Institute) scale, calibrated in terms of degrees API (°API). The API gravity is inversely proportional to the density of the crude oil; hence lighter oils have higher degrees API. The relationship between the API gravity and the specific gravity of an oil is:

$$API\ \ gravity = \frac{141.5}{specific\ gravity @ 60^{\circ} F} - 131.5$$

[11] Viscosity is a measure of the resistance of a fluid to flow. It is measured in Pascal·second (Pa·s) or in poise (P). 1 P = 100 cP (centipoise) = 0.1 Pa·s.

[12] Permeability refers to the ability of a crude oil to flow through the pores in the reservoir rock to the well. It is defined as the ratio between the fluid flow rate and an applied pressure. Permeability is historically measured in Darcys (D). Typical commercially exploited oil reservoirs have permeability ranging between 0.1 mD and 20 D.

The typical porosity of a reservoir rock is about 20%, but varying between 3 and 40%, depending on the arrangement of its grains, the depth and the type of rock. Oil and natural gas are found dispersed within the pores of the reservoir rock, together with water trapped in the sediment during its formation, called *connate water* (Figure 3.1). The porosity of the reservoir rock (i.e. the magnitude, interconnectivity, the pore size and shape) and the viscosity and gravity of the crude oil influence the flow of oil within the reservoir in the application of a pressure, which in turn affects oil recovery operations.

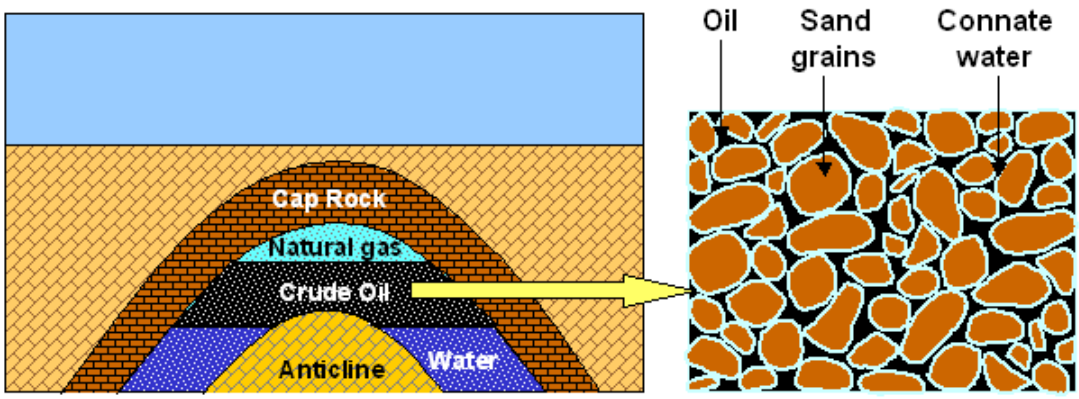

Figure 3.1: A typical 'anticline' oil reservoir resulting from the upward folding of geologic strata (left) and a schematic of an oil occurrence within the reservoir (right).

3.2 Oil Recovery Techniques

Oil recovery techniques have traditionally been grouped into three categories, based on when they are likely to be implemented in a typical oilfield: primary, secondary and tertiary oil recovery.

Primary recovery techniques are typically applied during the initial production phase of an oilfield, exploiting the pressure within the reservoir and using pumps to drive the oil to the surface. The pressure difference developed between the reservoir and the bottom of the oil producing well forces oil to flow towards the well. This is called *reservoir drive*. Reservoir drive is the result of the combination of a number of physical mechanisms:

- *Natural water drive* resulting from the rise of the water layer below the oil column in the reservoir, displacing oil upward into the well. The root cause of this is the inflow of water into the reservoir from adjacent aquifers.
- *Gas-cap drive* resulting from the expansion of the natural gas at the top of the reservoir, above the oil column, which displaces the oil downward in the direction of the producing wells.
- *Dissolved gas drive* that results from the dissolution and expansion of gas initially dissolved in the crude oil.
- *Gravity drainage* resulting from the movement of oil within the reservoir from the upper to the lower parts where the wells are located, driven by gravitational forces.

After reservoir drive diminishes as a result of oil and gas extraction, pumping is used to maintain oil production. The primary recovery stage is completed either when the reservoir pressure is too low to maintain economical production rates, or when the ratio of gas (or water) to oil extraction is high. The primary oil recovery factor (i.e. the ratio between the oil produced during primary recovery and the original oil in place -OOIP-) depends on such factors as the geological characteristics of each reservoir, the viscosity of oil, and the reservoir pressure. It typically ranges between 5-15% of OOIP.

When production by primary recovery methods is no longer viable, *secondary recovery* methods are applied. They rely on the supply of external energy into the reservoir in the form of injecting fluids to increase reservoir pressure, hence replacing or increasing the natural reservoir drive with an artificial drive. This is typically achieved by injecting water (*water-flooding*) in the reservoir using a number of injection wells. Although water flooding is used so extensively that this term has become synonymous to secondary oil recovery, other fluids, i.e. liquids or gases, may also be injected into the reservoir to achieve the same goal. Natural gas can be injected either in the gas-cap to increase the volume of gas within the reservoir, hence increasing reservoir pressure and displacing oil downward to the production wells, or into the oil bank to displace oil, however, without mixing with it (a process called *immiscible displacement*). In this context, CO_2 has also found a very limited number of applications worldwide. Many authors, however, include CO_2 displacement in the family of enhanced oil recovery operations. This is further discussed in subsequent sections of this Chapter. Immiscible gas displacement is not as efficient as water flooding, hence it is used less frequently today. Furthermore, the re-injection of natural gas into an oilfield can compromise the economics of such a project since the sales of the gas may be more profitable. Both the re-injection of natural gas, extracted during oil recovery, back to the oil reservoir and the injection of water have been practised successfully in the North Sea. The end of the secondary oil recovery process is dictated by economic criteria. A typical recovery factor from water-flood operations is about 30%, depending on the properties of oil and the characteristics of the reservoir rock. On average, the recovery factor after primary and secondary oil recovery operations is between 30 and 50% [22]. The oil recovery factor in the North Sea after primary and secondary recovery currently ranges between 45 and 55% while in some fields it has approached 70% [23].

Tertiary oil recovery refers to a number of sophisticated operations that are typically done towards the end of life of an oilfield, to maintain oil production and produce an additional 5-15% OOIP (Figure 3.2). This is achieved by altering the flow properties of crude oil and the rock-fluid interactions in the reservoir to improve oil flow. One of these techniques is CO_2-EOR.

With the evolution of knowledge on oil recovery, operations have, however, lost their traditional order of application. In an increasing number of reservoirs, operations otherwise named as 'tertiary' are performed first, such as for the extraction of heavy viscous oils, or they replace traditional secondary oil recovery operations. Hence, the term 'tertiary oil recovery' has recently been disfavoured in the literature and substituted by the term *enhanced oil recovery* or EOR. The term *improved oil recovery* (IOR) is also frequently used in the same context, however it refers to a broader range of processes that lead to increased recovery, such as improved reservoir

characterisation and management, advanced drilling techniques, and other production enhancement methods, including EOR.

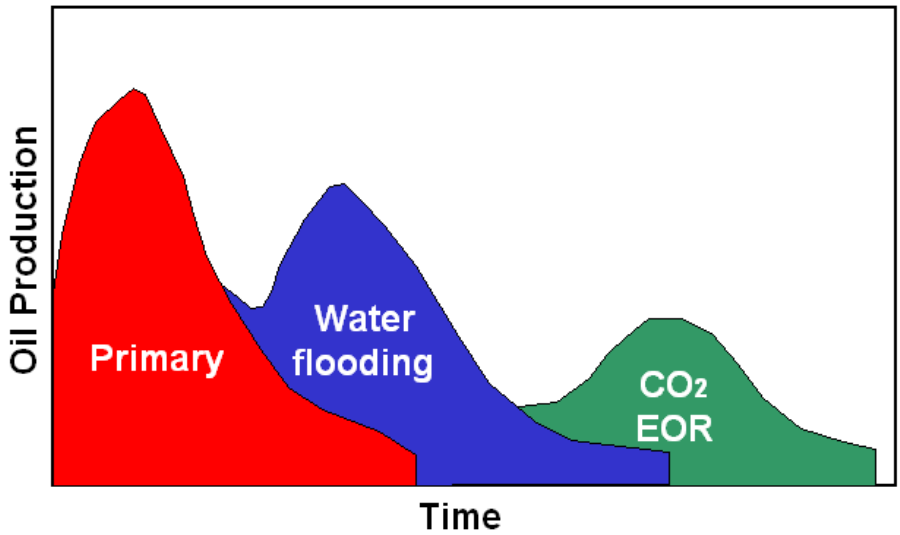

Figure 3.2: Expected sequence of oil recovery methods in a typical oilfield

3.3 Fundamentals of CO_2-EOR

A significant amount of oil, more than half of the originally contained in the reservoir, is usually left underground after secondary oil recovery. The residual oil remains largely as isolated droplets trapped in the pores of the reservoir rock or as films around rock grains. The saturation of the reservoir rock with oil is about 20-35% in regions swept by the displacement fluids during secondary recovery (water or natural gas), and significantly higher in the unaffected volume of the reservoir. An effective EOR process must mobilise these dispersed oil droplets and form an oil bank that can move towards the production wells. This needs to be accomplished both on the micro-scale, at the pore level, and also on the macro-scale affecting the largest possible volume of the reservoir. The injection of CO_2 in the reservoir can mobilise this stranded oil. When introduced in the reservoir CO_2 interacts chemically and physically with the reservoir rock and the contained oil, creating favourable conditions that improve oil recovery. These conditions include (i) the reduction of the capillary forces that inhibit oil flow through the pores of the reservoir by reducing the interfacial tension between oil and the reservoir rock; (ii) the expansion of the volume of the oil (*oil swelling*) and the subsequent reduction of its viscosity; (iii) the development of favourable complex phase changes in the oil that increase its fluidity, (iv) the maintenance of favourable mobility characteristics for oil and CO_2 to improve the volume sweep (replacement) efficiency [13].

[13] CO_2 as a gas has the tendency to move faster than oil within the reservoir. For CO_2-EOR to be effective, the mobility of CO_2 must be similar to that of oil. The mobility of each phase depends on its effective permeability, which quantifies how the presence of other fluids hinders its flow, and its viscosity. In general the volumetric sweep efficiency decreases as the mobility ratio between CO_2 and oil increases. When the mobility ratio is larger than unity, fluid flow becomes unstable and the

Two processes have been developed for CO_2-EOR: miscible displacement and immiscible displacement. The applicability of each process depends on the reservoir conditions. These two processes are described in the following sections of the Chapter.

It is noted that CO_2-EOR processes are also distinguished by some authors based on the type of CO_2 injection in the reservoir: the water alternating gas (WAG) method and the gravity stable gas injection (GSGI) method. In WAG injection, CO_2 is injected first to swell the oil and improve its fluidity. Then, water is used to displace the oil bank towards the production well. The concurrent flow of water and CO_2 in the oil reservoir also results in the reduction of the mobility of each phase, reducing the occurrences of viscous fingering (Figure 3.3). A schematic of the process is shown in Figure 3.6. In addition, the presence of water in the reservoir improves oil recovery, as it forms a fast diffusion path for CO_2 to reach oil trapped in the pores of the reservoir rock. There are different WAG injection patterns used depending on the reservoir characteristics. In these patterns, both the amount of CO_2 injected before the water, known *as CO_2 slug size*, and the injection rate may vary (see Figure 3.4).

Another method for introducing CO_2 in the reservoir is to inject it in the crest, forcing the oil to move downwards and to the direction of the rim, where the producing wells are located, a method called gravity stable gas injection (GSGI). CO_2 (which can be miscible or immiscible to oil) is used for maintaining reservoir pressure and for stabilising displacements via gravity drainage to increase sweep.

WAG has an advantage over GSGI in that it can be performed on a small scale, while in general, GSGI is applied in the whole oilfield. Hence GSGI projects are likely to recover more oil and store larger CO_2 volumes [27].

3.3.1 Miscible CO_2 displacement method

Under favourable reservoir pressure and temperature conditions and crude oil composition, supercritical[14] CO_2 can become miscible with petroleum, i.e. the crude oil and CO_2 mix in all proportions forming a single-phase liquid. As a result of this interaction, the volume of oil swells, its viscosity is reduced, and surface tension effects diminish, improving the ability of the oil to flow out of the reservoir.

Carbon dioxide is however not instantaneously miscible with oil at first contact. Miscibility conditions develop dynamically in the reservoir via composition changes when the CO_2 flows through the reservoir and gradually interacts with oil, a process called *multiple contact miscibility* (MCM). When the CO_2 is injected in the reservoir and is brought in contact with crude oil, initially its composition is enriched with vapourised intermediate components of the oil. This local change in the composition of oil enables the miscibility between the oil and CO_2 (*vapourising process*) forming a miscible zone between the oil bank and the injected CO_2. Practically, however, the

displacement front becomes non-uniform. As a result the CO_2 does not sweep the maximum possible volume of the reservoir and may by-pass the oil bank reaching the producing well before the oil does.

[14] In practical terms, a fluid in supercritical state could be considered as a dense but extremely fluid liquid.

interaction between CO_2 and oil is not that simple, involving the formation of a number complex liquid and vapour phases [22].

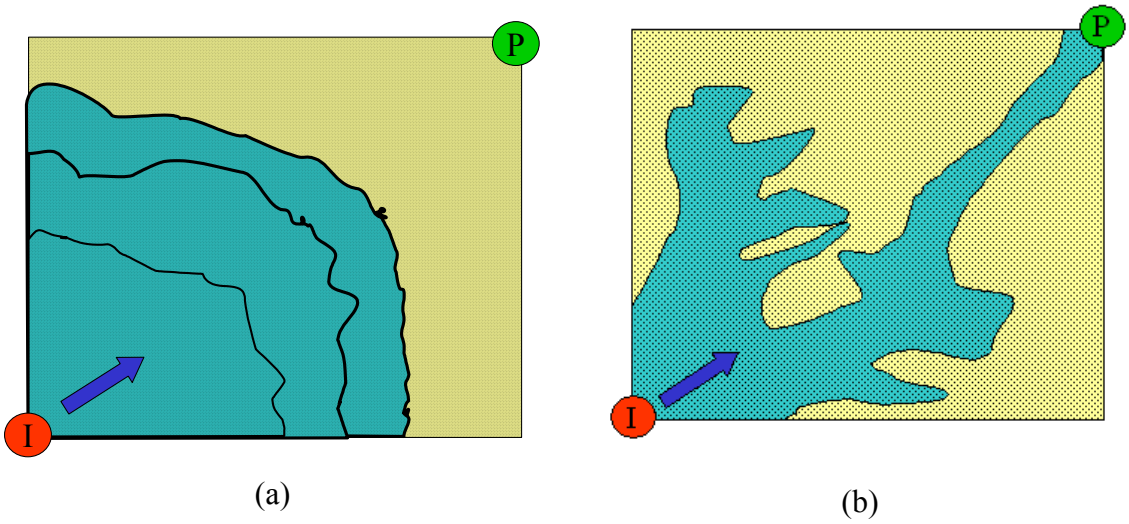

Figure 3.3: A stable front between the injected CO_2 and the oil (left) ensures the complete sweep of the reservoir maximizing recovery. Viscous fingering (right) results in the breakthrough of CO_2 leaving large volumes of the reservoir unaffected by the injection of CO_2 (These drawings refer to a quarter of a five-spot injection pattern [28]. (I) and (P) refer to injection and producing wells respectively) (Drawn after [22])

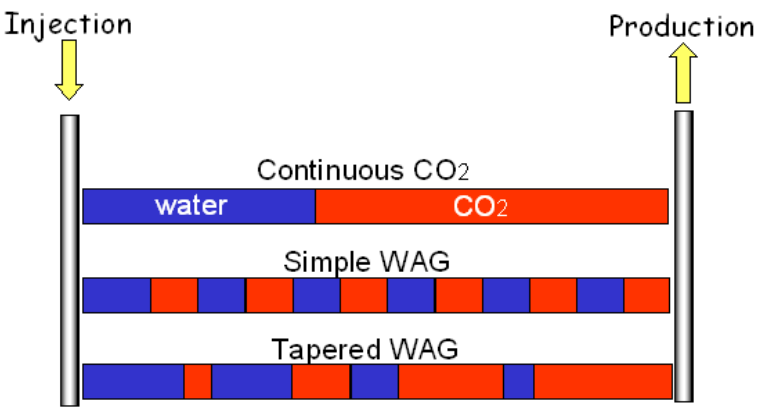

Figure 3.4: WAG patterns (after [32])

The miscibility of CO_2 in crude oil is strongly affected by pressure. A *minimum miscibility pressure* (MMP) is required so that CO_2 becomes fully miscible with oil. At that pressure, the density of CO_2 is similar to that of the crude oil[15]. The value of

[15] Typically, MMP is above the critical pressure of the CO_2, hence CO_2 is injected in a supercritical state. Moreover, upon injection, CO_2 must remain in supercritical state within the reservoir; a phase change to gas can cause problems to the EOR operation by inhibiting the flow of fluids within the

MMP depends on the composition of crude oil, the purity of CO_2 and the reservoir conditions (pressure and temperature). Hence, a miscible CO_2-dispacement technique can only be implemented when CO_2 can be injected at a pressure higher than that of MMP, which in turn must be lower than the reservoir pressure. These conditions are typically achieved in the oil reservoirs of the North Sea found at depths greater than 700 m[16]. Thus, the knowledge of MMP is a fundamental requirement for screening the applicability of the process in an oilfield. To this end significant research work has focused on the measurement and prediction of MMP. The MMP can nowadays be measured experimentally or predicted using empirical equations and thermodynamic modelling with a very good accuracy. A review of the current knowledge on the matter is presented in [22]. In summary, low values for MMP, necessary for the applicability of the process to a large number of oilfields, are favoured by:

- High CO_2 densities, e.g. 0.4-0.75 g/cm^3, necessary to achieve miscibility in the C_5 to C_{30} hydrocarbons of the crude oil [24].
- Low reservoir temperatures to maximise CO_2 density
- Light and medium crude oils (lighter than 22°API) with a low concentration of aromatics.
- High CO_2 purity, since the presence of nitrogen, sulphur, SO_X, NO_x and other contaminants in the CO_2 stream increases MMP [25]. This has significant implications for the required purity of CO_2 captured from combustion plants for EOR use.

The MMP for light, low sulphur North Sea crude oils is within the range of 18 - 25 MPa [26].

In theory, all oil contacted with CO_2 can be recovered. However, in practice, additional oil recovery is usually limited to about 5-20% of OOIP [27]. Reasons that affect oil recovery include:

- The need for a finite distance for CO_2 flow through the reservoir before full miscibility is achieved.
- Unstable flow (viscous fingering) resulting from the easier flow of CO_2 in the reservoir than that of oil, that leads to oil trapping (Figure 3.3).
- Early breakthrough of CO_2 resulting from unstable flow (as above) and gravity effects resulting from significant density differences between CO_2 and oil or from a high permeability of the reservoir rock, which leads to phase segregation (Figure 3.5).
- The need of CO_2 to mobilise also some water in the reservoir, which has been left behind after water flooding.

To prevent the occurrences of unstable flow and to reduce the amount of CO_2 that is needed for the process, CO_2 is typically injected into the reservoir alternately with water, the WAG technique described above, since water sweeps through the reservoir

reservoir and reduce significantly the efficiency of the process. As such the reservoir temperature and most importantly reservoir pressure should be above those of the critical point of CO_2.

[16] Assuming that the reservoir is connected to the seawater the critical pressure is achieved at a depth of around 670 m, considering an average hydrostatic pressure gradient of 10.5 MPa/km. If the reservoir however is not linked to the seawater it may be over-pressurised or under-pressurised. Similarly, the critical temperature is reached at a depth of 700 m, assuming a surface temperature of 10 °C and a geothermal gradient of 30°C/km.

more uniformly and hence more efficiently than CO_2. A schematic of the process is shown in Figure 3.6.

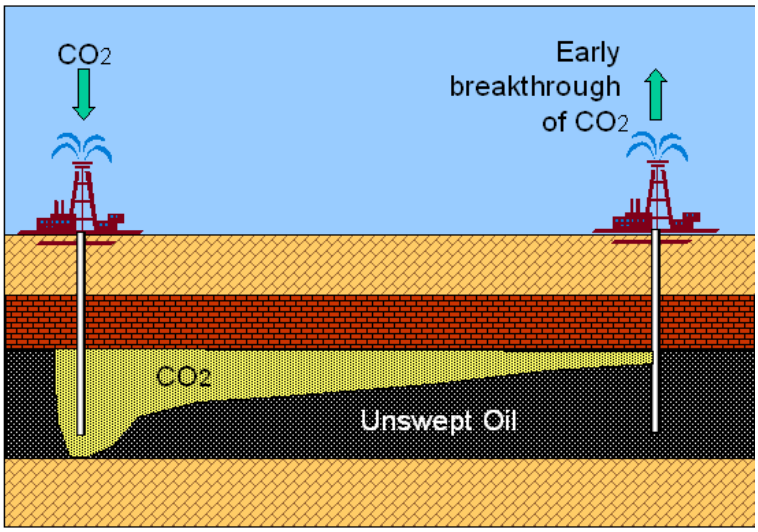

Figure 3.5: Early breakthrough of CO_2 due to non-optimal viscous flow and gravity effects

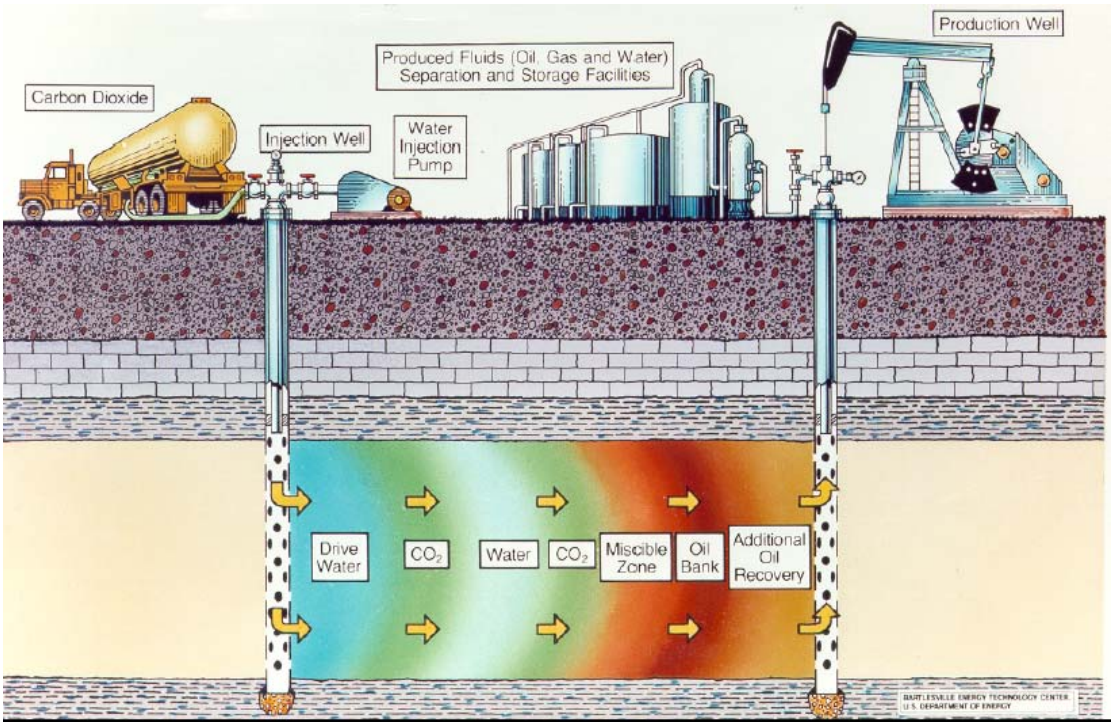

Figure 3.6: A schematic of a WAG miscible CO_2-EOR operation [29]

Under common practices, oil producers aim at maximising oil recovery and at minimising the consumption of CO_2, as the latter is a commodity that could be reused for EOR if recycling of the CO_2 that breaks through the producing wells appears to be more economic than venting and purchasing all new CO_2. Typically the purchase and

pre-treatment of CO_2 before injection accounts for 50-80% of the capital and operating costs in ongoing CO_2-EOR projects [3, 30, 32]. Hence, the breakthrough of as much as possible of the injected CO_2 is sought after at the producing wells together with oil in miscible operations. The CO_2 that leaves the reservoir is separated from oil, recompressed and injected back into the reservoir joining the stream of fresh CO_2 imported in the project. Nevertheless, some CO_2 remains permanently underground, trapped in the pores of the reservoir rock or dissolved in oil and water. Data from the Rangley Weber Project in the USA suggest that for each part of CO_2 retained in the oil reservoir, three parts are re-circulated and 10% is vented in the atmosphere [30].

It is however important to note that if financial benefits arise from storing CO_2 underground, CO_2 injection may have to be optimised for maximising both oil recovery and CO_2 retention underground. Ongoing work indicates that such optimisation will be field specific and will necessitate a trade-off between oil recovery and CO_2 sequestration [31].

Onshore miscible displacement is a commercial technology. Operations can be deployed towards the conventional end of life of a reservoir, a few years before and even as late as about the cease of secondary oil recovery since there is no need for configuration changes in the well pattern. Miscible projects can use the same wells as waterflooding. Furthermore, projects can be implemented to parts only of the reservoir, on a small scale. Incremental oil can be produced relatively quickly, typically after 1-5 years from the start of the project depending on the reservoir characteristics and the spacing between the injection and the producing wells.

A miscible displacement operation may use the same equipment utilised for water-flooding. The additional infrastructure needed for a miscible displacement project in an existing oil recovery operation include:

- Reception and conditioning facilities for the CO_2 (including the addition of corrosion inhibitors –see below-),
- Modified injection and production wells (new wells may not be needed if water-flooding has already been practised)
- CO_2 separation membrane facilities
- CO_2 compression and recycling lines
- Monitoring equipment

3.3.2 Immiscible CO_2 displacement method

The injection of CO_2 in a reservoir can still increase oil recovery, even when MMP is not reached, for example in low-pressure oil reservoirs or in the case of heavier oils. Under such conditions, the CO_2 although not fully miscible with oil can still partially dissolve in it causing some swelling. It is reported that the addition of CO_2 in poor quality heavy oil may reduce its viscosity by a factor of 10 [33]. More importantly, in immiscible displacement, the role of CO_2 is similar to that of water in secondary oil recovery processes, i.e. to raise and maintain reservoir pressure. Although water flooding offers higher recovery efficiencies, the use of CO_2 to raise reservoir pressure has been considered in limited number of projects when the permeability of the reservoir rock is too low or geologic conditions do not favour the use of water.

In this process, CO_2 is typically injected in GSGI mode although WAG is also possible. CO_2 is typically injected at slow rates at the crest of the reservoir aiming at

filling the pore volume of the reservoir rock. The injected gas creates an artificial gas cap, pushing oil simultaneously downwards and towards the rim of the reservoir where the producing wells are located (Figure 3.7). The presence of water within the reservoir reduces the effectiveness of the process as it inhibits oil flow. As such this process may not be effective when applied after significant water flooding.

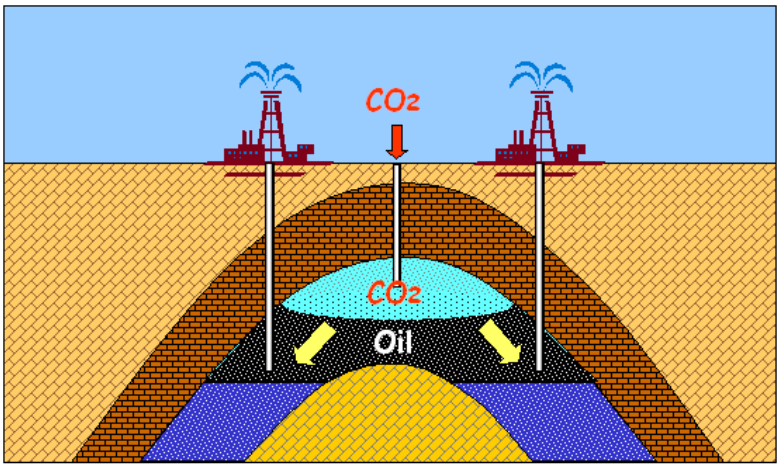

Figure 3.7: A schematic of the immiscible displacement technique

The immiscible displacement process has seen very limited applications so far, the reason being the unfavourable economics. While significant amounts of CO_2 are required and a number of new wells need to be constructed, additional oil production is very slow. Up to 10 years of injection may be required before the project starts producing additional oil. Furthermore, an immiscible project is typically implemented in the whole reservoir, limiting the opportunities for smaller scale implementation.

The growing importance of the potential economic benefits of carbon capture and storage in the frame of the EU emissions trading scheme could however, make this process increasingly attractive commercially. Immiscible displacement projects can store larger volumes of CO_2 than miscible displacement projects. While in the latter, the amount of CO_2 stored underground is dictated by its dissolution from oil and to a lesser extent to oil and water left underground, in the former, the amount of CO_2 stored is limited only by the porosity of the reservoir rock. Furthermore, while CO_2 breakthrough is unavoidable in miscible displacement operations (Figure 3.5), immiscible displacement projects may be designed to eliminate this, as would be needed for permanently retaining CO_2.

3.4 Experience with CO_2-EOR

3.4.1 A Worldwide Snapshot

CO_2-EOR is an established and successful technique for recovering additional oil, mainly from onshore North American oilfields. 79 CO_2-EOR operations were active in 2004 worldwide [34]. Nearly all of them, 70 miscible CO_2-EOR projects and 1 immiscible, were implemented in the USA. In addition, there are 2 active miscible displacement CO_2-EOR projects in Canada, 5 immiscible displacement pilot fields in Trinidad and 1 commercial immiscible displacement operation in Turkey (Table 3.1). These projects produced cumulatively approximately 230000 barrels of oil per day in 2004, which is approximately 0.3% of world oil production. In the 1980's a number of small CO_2-EOR projects were operated in Hungary, however they were terminated in the mid-1990's [30]. There have been no CO_2-EOR projects deployed in the North Sea[17] with the exception of a miscible CO_2-EOR project undertaken in the Egmanton oilfield. This project was however unsuccessful due to low injectivity[18] [23].

Clearly, the USA is in the forefront of the implementation of the method, accounting for 94% of the worldwide CO_2-EOR oil production. Oil production using CO_2-EOR has increased steadily in the USA since the 1980's while in 2004 it represented 31% of the US oil production from all enhanced oil recovery methods combined, equivalent to 3.6% of the total US oil production. Moreover, five large projects account for almost half of the total CO_2-EOR oil production with production rates ranging between 41000 barrels per day (Wasson-Denver project) and 7200 barrels per day (Means project). The first miscible displacement project commenced in 1972 (at the SACROC field in the Permian basin). Since then, CO_2-EOR production grew modestly in the 1970's and early 1980's and accelerated rapidly during the late 1980's and 1990's despite low oil prices. Three main reasons contributed to this [30]: (a) the reduction of recovery costs due to technological progress; (b) the reduction in CO_2 costs resulting from the increased CO_2 supply from natural deposits and the construction of long distance pipelines that currently provide approximately 30 million m^3 of CO_2 on a daily basis to the Permian basin [32]; and (c) the restructuring of oil companies that permitted them to operate more cost effectively. Furthermore, some fiscal incentives had an impact on investment. The historical evolution of enhanced oil production, as well as the number of related projects are shown in Figure 3.8.

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[17] In June 2005, BP, ConocoPhillips, Shell and Scottish and Southern Energy (SSE) announced the development of an EOR-CO_2 project in Scotland. The project plans to capture the CO_2 from a 350 MW natural gas power plant and transport it 240 km to the Miller oilfield, where it will be used for EOR.

[18] Injectivity refers to the relationship between the pressure gradient and flow rate in the region near the well-bore. In other words, it refers to the ability of the well to accept CO_2.

Table 3.1: Number of active CO_2-EOR projects and production rates [34]

Country	*Project Type*	*No of projects*	*Production Rate (b/d)*
USA	*Miscible*	70	205 775
	Immiscible	1	102
Canada	*Miscible*	2	7 200
Turkey	*Immiscible*	1	6 000
Trinidad	*Immiscible*	5	313

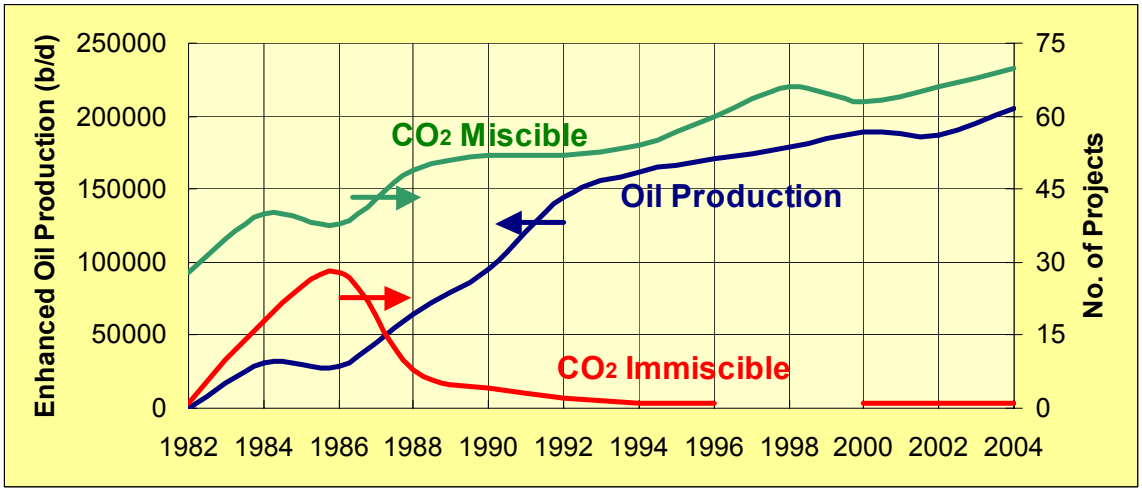

Figure 3.8: Evolution of the number of CO_2-EOR projects and their cumulative production in the USA [34]

3.4.2 Miscible CO_2-EOR Operations: Lessons Learnt

The increasing number of miscible displacement projects has generated significant experience and has provided valuable insights into the underlying physical and chemical mechanisms for oil recovery. Detailed data about the operating conditions and the performance of individual projects are however not publicly available.

Most of the miscible displacement projects are located in the southwestern USA, in the Permian basin of western Texas and eastern New Mexico. Other projects have been developed in the Rocky Mountain region, the Gulf of Mexico and the Midwest. Most of these projects utilise naturally occurring CO_2 from high-pressure high purity underground deposits. For example, the McElmo dome in Colorado contains over 283 million m^3 of CO_2 at a pressure of about 13.5 MPa [30]. Only a small number of projects use CO_2 captured from anthropogenic sources, such as waste streams from gas processing and fertiliser plants. According to a recent review [3], the annual supply of CO_2 from these plants to EOR projects was 5.7 million tonnes. The largest

of them is the Weyburn project in Canada, where 1.8 million tonnes of CO_2 are captured annually from a coal gasification plant in the USA and transported via a 325 km long dedicated pipeline to the Weyburn oilfield that produces 10000 barrels of incremental oil daily. Two other gas processing plants in the USA supply each 1.2 million tonnes annually to the Rangely and Shanon Ridge EOR fields.

CO_2-EOR projects have been managed with varying success in a wide range of reservoir conditions [24]:

- Shallow and deep reservoirs (1000 m – 3000 m)
- Tight and very permeable reservoirs
- Low and medium viscosity oils (0.3 - 6 cp)
- In sandstone and carbonate reservoir rock.

Data from 10 miscible displacement projects in the Permian basin indicate that the net injection of CO_2 into an oilfield (i.e. the difference between the total CO_2 injection and the recycled CO_2) is on average 164 m^3 per barrel (bbl) of incremental oil (approximately equivalent to 330 kg/bbl). This value has shown to vary between 270 kg/bbl in the Rocky Mountain projects to 400 kg/bbl in the Midwest. On average, oil recovery has been 10.9% OOIP in the Permian basin, 7.6% in the Rocky Mountains and 7.2% in mid-west [30, 35]. Overall, the evaluation of results from a large number of US projects suggest that the average incremental recovery of oil lies within the range of 4-12% OOIP while the net volume of CO_2 injected is in the range of 10-45% of the volume occupied by the hydrocarbons in the reservoir [24]. The highest oil recovery efficiencies are associated with the implementation of the *tapered WAG* injection technique (see Figure 3.4) [32] where the ratio of injected water to CO_2 changes with time, starting with larger CO_2 slugs that are progressively reduced in size.

Not all oil reservoirs are suitable for CO_2-EOR for technical and economic reasons. Based on gained experience, some generic rules have been formulated for screening potential miscible displacement projects:

- The project should be able to operate just above the minimum miscibility pressure to ensure miscibility and minimise CO_2 consumption.
- The saturation of the reservoir with remaining oil after water-flooding should be relatively high, at least 35-40% [32].
- The reservoir should be homogeneous with a good connectivity throughout the reservoir and low vertical heterogeneity, and with a medium to high permeability, more than 100 mD [36].
- Oil gravity should be higher than 35°API (equivalent to lower than 0.85 specific gravity) and oil viscosity in the range of 1-2 cp [36].

Finally, although many reports indicate that a successful water-flooding is a good indicator for a successful CO_2-EOR project, this is disputed based on the argument that at the end of a water-flooding there is significant amount of water to be mobilised by the CO_2.In addition, there are significant CO_2 losses caused by its dissolution into the water [37].

Moreover, general problems with miscible displacement, that in many cases have caused the failure of projects, have been recognised:

- Insufficient research before starting a project. Reservoir geology and petrophysics need to be well understood before a project commences. Low recovery efficiencies have resulted from (i) poor sweep of CO_2 within the

reservoir due to excessive heterogeneities (ii) slow response due to low injectivity, (iii) early gas breakthrough via high mobility paths (geological faults), due to insufficient description of the geology of the reservoir. This issue highlights the need for proper surveillance before the project starts, and for effective reservoir management.

- Reduction of reservoir pressure due to reduced injectivity that may result in loss of miscibility and hence reduction of recovery efficiency. The injectivity is reduced due to the change in permeability from the formation of precipitates (hydrates and asphaltenes[19]) near the wellbore, the lack of fracture of the reservoir rock when CO_2 is injected at elevated temperatures similar to those of the reservoir, hence minimising thermal stresses[20], etc. However, the pressure can be restored by increasing the injection rates in nearby wells.
- The formation of scales that can cause the failure of water pipelines and wells of an EOR project. CO_2 reduces the pH of water in the oil reservoir, dissolving calcium from limestones or from cementation minerals in sandstone formations hence increasing the concentration of calcium salts in the water produced from the oil wells. Subsequently, the reduction of pressure at surface causes the precipitation of calcite and the formation of scales.
- Corrosion of iron components by the use of CO_2, which when dissolved in water forms carbonic acid promoting corrosion and erosion.

3.4.3 Immiscible CO_2-EOR Operations: Lessons Learnt

Contrary to miscible displacement, only a very limited number of immiscible displacement projects have been developed. Furthermore, currently there is only one large-scale project that uses the technique, in the Bati Raman oilfield, in southeast Turkey, close to the Turkish-Iraqi border. The oilfield contains heavy oil with very low gravity (9° to 15° API) [30]. While traditional oil recovery techniques were able to yield just 1.5% of the OOIP, the injection of CO_2 coming from a nearby natural reservoir, commenced in 1986, produces 6000 barrels of oil per day. Overall, it has been estimated that 6.5% of OOIP will be recovered by EOR. The main mechanism for EOR is the significant solubility of CO_2 in oil (approximately 13 m^3/bbl), which causes oil swelling, despite the lack of miscibility, reducing the viscosity of oil by a factor of 10. Since the start of the project, approximately 1700 tonnes of CO_2 are injected daily, 16% to 60% of which is recycled. The principle mechanism for CO_2 retention underground is the high CO_2 solubility in un-recovered oil.

Furthermore, according to [34] only one small scale immiscible project is underway in the USA, and 5 pilot projects in Trinidad (see Table 3.1). A number of immiscible displacement pilot projects were initiated in the USA in the past (e.g. the Weeks Island, the Bay St Elaine and the Timbalier Bay projects). However their scaling up to full commercial projects was not successful despite the promising results from the pilot schemes. For example, the Weeks Island project failed due to the presence of a high pressure aquifer that did not permit the displacement of oil upon CO_2 injection

[19] Asphaltenes are high molecular weight hydrocarbons (>500)

[20] This phenomenon is intensified when most of the CO_2 injected has been recycled and hence is hot as a result of compression.

[32] despite the fact that the pilot project managed to yield 60% of the oil left after water flooding [38]. A number of immiscible displacement projects were also managed in Hungary in the 1980s and 1990's, taking advantage of a natural CO_2 reserve in the area. In this case, EOR was achieved by creating an artificial gas cap forcing oil towards the production wells. The overall CO_2 utilisation was 380 m^3 per barrel of oil extracted (equivalent to 760 kg/bbl).

Experience has shown that the conditions that favour immiscible displacement include [24]:

- High vertical permeability in the reservoir rock
- A substantial amount of oil to form a thick oil column
- A steeply dipping relief and good lateral and vertical communication through the reservoir
- Absence of fractures that reduce sweep efficiency

Despite the small experience in immiscible displacement, it has been estimated that the utilisation of CO_2 is within the range 280-400 m^3 of CO_2 per barrel of incremental oil or equivalently 560-790 kg/bbl [30, 39]. The process may yield approximately up to 20% of OOIP [40].

3.4.4 Comparison of miscible and immiscible displacement processes

The fundamental difference between the two CO_2-EOR processes discussed above lies with the interaction between the injected CO_2 and the crude oil. When the project can be managed at pressures higher than MMP, CO_2 is miscible to oil improving its flow behaviour. When the MMP is not achieved, CO_2 is either immiscible or partially miscible to oil. Oil recovery is then mainly facilitated by increasing the reservoir pressure to force the oil towards the well and by some oil swelling and viscosity reducing effects.

Assuming that miscible projects will be exploited by WAG and immiscible projects by GSGI, a miscible project can be initiated any time before the cessation of operations as the well pattern remains the same with water flooding. On the other hand, since the well pattern is fundamentally different for GSGI immiscible projects, they can start at around the cessation of oil production.

Table 3.2 summarises the key characteristics of the two techniques.

Table 3.2: Comparison between miscible and immiscible displacement CO_2-EOR techniques

	Miscible	*Immiscible*
Project Duration	Short (<20 years)	Long (min. 10 years)
Project Start	Before or after waterflooding is completed	After waterflooding is completed
Oil Extraction	Early (~1-3 years)	Late (>5-8 years)
Scale of Project	Smaller	Larger
Recovery Mechanism	Complex	Simple
CO_2 Recycling	Unavoidable	Avoidable
Oil Recovery Potential	Lower (4-12% OOIP)	Higher (~18% OOIP)
CO_2 Storage Potential	Lower (0.3 t/bbl)	Higher (up to 1 t/bbl)
Experience	Significant	Little

3.4.5 Competing oil recovery processes

CO_2-EOR is just one of the processes that have been developed to increase oil recovery. The properties of crude oil, the characteristics of the reservoir rock and the distribution and saturation of oil into the reservoir after the primary and secondary recovery operations are unique for each particular project. The variability of reservoir conditions has led to the development of a number of EOR techniques that can be considered for the further exploitation of an oil field, which can be competing with CO_2-EOR. The selection of the most suitable EOR process for each project is governed by the reservoir characteristics, oil composition, and the availability of chemicals needed for each process (see below). Overall, these factors have an impact on the economics of the project, which is finally the determining factor for the selection of the most appropriate EOR process. The competing EOR processes are presented briefly below [42][21]:

- *Chemical processes*: These processes are based on the injection of chemicals such as surfactants or alkaline agents (which induce the formation of natural surfactants), ahead of the water, to decrease the capillary forces that inhibit oil flow through the porous reservoir rock, thus improving macroscopic and microscopic oil sweep. The processes are ideal for rocks with heterogeneities and a high permeability. A second group of related processes (*mobility control processes*) use viscous polymer solutions ahead of the injection of water to form a front that can reduce the mobility of the injected water along high permeability faults, thus permitting a more uniform volumetric sweep of the

[21] There is not a common agreement regarding the grouping of EOR processes to categories. As such, the classification of these techniques varies significantly in the literature.

reservoir. They are technically complex processes and require large amounts of chemicals, making their application reasonable only in limited cases. A surfactant flooding project was trialled in the Bothamsall oilfield, polymer injection in Beatrice and Thistle and solvent injection in Ninian, all of them with inconclusive results [23].

- *Other miscible displacement processes:* These processes are based on the injection of gases that are miscible with oil. The achieved miscibility reduces capillary forces and the viscosity of oil. Suitable solvent gases besides CO_2 include methane, liquefied petroleum gas (LPG), nitrogen and flue gases. Such techniques have already been implemented in the Magnus, Miller, Brae S and Alwyn N. oilfields of the North Sea since the late 1990s.
- *Thermal processes:* These processes aim at reducing the viscosity of oil by increasing its temperature and modifying its composition via vapourisation and thermal cracking. This is achieved by increasing the temperature of the reservoir by either injecting a hot fluid (such as steam or hot water) in a continuous or cyclic pattern, or by producing heat within the reservoir by combusting some of the oil in place. Thermal EOR is the most widely used technique, mostly suitable for heavy oils. However the technique is not very relevant for the North Sea, where the oilfields are relatively deep and oil viscosity is low.
- Other methods include microbial EOR (that is based on the injection of a solution of micro-organisms and nutrients, which produce surfactants, CO_2 and other compounds that improve the fluidity of oil), microwave EOR (based on the underground application of microwaves to heat and mobilise oil), earthquake stimulation (using high-power surface vibrators), etc. Microbial EOR has been trialled in the Beatrice, Ninian, Murchison and the Norne fields, the results, however, have been uncertain.

Approximate screening criteria have been proposed to assist in the selection of the appropriate EOR method for each particular oil reservoir. These are summarised in Table 3.3 [22].

In addition to EOR techniques, advanced drilling and well technologies and improved reservoir management techniques can play an important role in improving oil recovery. Advances in these areas have enabled the exploitation of reservoirs deemed uneconomic in the past. All these options will compete for investment and may sideline CO_2-EOR projects.

Table 3.3: Screening criteria for EOR processes (from [22])

	Oil Properties				*Reservoir Properties*				
EOR Method	**Gravity (°API)**	**Viscocity (cp)**	**Composition**	**Oil Saturation (%)**	**Formation Type**	**Net thickness (m)**	**Average permeability (mD)**	**Depth (m)**	**Temperature (°C)**
Miscible Gas Injection Methods									
CO_2	>22 (36)	<10 (1.5)	High % of C_5-C_{12}	>20 (55)	Sandstone Carbonate	Wide range	Not critical	>833	Not critical
Nitrogen / Flue Gases	>35 (48)	<0.4 (0.2)	High % of C_1-C_7	>40 (75)	Sandstone Carbonate	Thin	Not critical	>2000	Not critical
Hydrocarbon (e.g. N. gas)	>23 (41)	<3 (0.5)	High % of C_2-C_7	>30 (80)	Sandstone Carbonate	Thin	Not critical	>1333	Not critical
Chemical Methods									
Micellar- / Alkaline- / Polymer Flooding	>20 (35)	<35 (13)	Light & intermediate	>35 (53)	Sandstone	Not critical	>10 (450)	<3000 (1083)	<90 (26)
Polymer Flooding	>15 <40	>10 <150	Not critical	>70 (80)	Sandstone	Not critical	>1000 (800)	<3000	<90 (26)
Thermal methods									
Combustion	>10 (16)	<5000 (1200)	Asphaltic components	>50 (72)	High porosity Sandstone	>3	>50	<3833 (1167)	>38 (60)
Steam	>8 (13.5)	<200000 (4700)	N.C.	>40 (66)	High porosity Sandstone	7	>200	<1500 (500)	Not critical

Values in parenthesis represent the approximate average values for current field projects.

3.5 Barriers to the Implementation of CO_2-EOR

Despite the potential for increasing oil production and for storing some CO_2 emissions, CO_2-EOR has not been implemented in Europe yet. The deployment of such projects is hindered mainly by the lack of CO_2 supply and poor economic performance followed by environmental concerns and unclear legal/regulatory frames. Technical challenges do not appear to be major bottlenecks to implementation, however, they should not be overlooked. This section highlights these issues.

This section however does not address the subjects related to the separation and capture of CO_2 or those related to conventional oil recovery. The former have been discussed in detail in other publications (e.g. in [2]), while the latter have been the focus of industrial research for decades. An important point however, related to carbon capture, that is brought forward in this report is the need for high purity CO_2 devoid of typical components found in flue gases, given that CO_2 purity has a significant effect on MMP. This requirement for CO_2-EOR operations will have a significant impact on developing CO_2 capture technologies with high capture efficiency.

The principal barriers to broader implementation of CO_2-EOR are:

- Technical
  - The geological characteristics of the North sea reservoirs
  - Poorly understood physico-chemical interactions between CO_2 and the contents of the reservoir
- Economics
  - Cost of CO_2 supply
  - Lack of financial incentives for CO_2 storage
  - Modifications to infrastructure
- Environmental concerns for permanent and safe CO_2 storage - Public acceptance
- Legal / regulatory issues
- Commercial barriers

These issues are discussed below.

3.5.1 Geological Assessment – North Sea Challenges

Like oilfields in the USA, the oilfields in Europe have been thoroughly assessed and described during the process of exploration, appraisal, and primary and secondary recovery. Experience in the USA suggests that evidence of successful secondary recovery through water injection may provide confidence in the feasibility of miscible CO_2 displacement projects. Overall, there is very good experience of successful implementation of water flooding in the North Sea, and much information has been collected on well connectivity during this process. Hence, the geology of the European oilfields is well characterised.

As discussed earlier in this Chapter, there is significant experience in managing CO_2-EOR projects, accumulated in the USA. Nevertheless, the standard practices for the

US oilfields may not be directly transferable to the European oilfields for two main reasons. First, there are significant differences in the geology between the North American oilfields where CO_2-EOR projects have been implemented and the North Sea oilfields, shown in Table 3.4. Secondly, US fields are onshore while most of the European oilfields are offshore. Oil recovery offshore relies on different infrastructure and exploration patterns from those used in onshore CO_2-EOR projects.

One outstanding aspect of the North Sea oilfields is the diversity of the reservoir characteristics. Hydrocarbon discoveries have been made in rocks from Devonian (e.g. Buchan) to Eocene (e.g. Gannet A) age. Although primarily clastic reservoirs, the facies vary from desert through deltaic to deep marine in terms of deposition. Unlike in the USA, carbonate reservoirs are rare, apart from the chalk of the Ekofisk area. The reservoir stratigraphy is also typically more complex, containing faulted blocks and steeply dipping beds.

Table 3.4: Main differences between North Sea and USA/Canada EOR reservoirs

	North Sea	*USA and Canada*
Reservoir Type	Sandstone	Carbonate
Permeabilty	High (typically > 500mD)	Low (typically < 20 mD)
Reservoir Depth	High	Low
Well Productivity	High	Low
Well Spacing	High	Low
Stratigraphy	Fault blocks	Less Faulted
	Steeply Dipping Beds	Horizontal Beds
Oil Type	Predominantly Sweet	Sour and Sweet
	High API	28-42 API

While the miscible displacement process has been proven successful in low permeability, low dipping formations in the USA, the geology in the North Sea is dominated by high permeability dipping reservoirs. High North Sea permeabilities mean that gravity effects may be more important than viscous flow compared to the US projects, which may affect the flow of CO_2 in the reservoir, and thus the success of the project. Hence detailed field-specific reservoir modelling will be required for North Sea fields to address the significant differences from the US reservoirs.

The greater depth of the North Sea fields leads to higher reservoir temperatures and pressures. The effects however of higher pressure counter-balance those of the higher temperatures, indicating that the density of supercritical CO_2 injected in the US and the North Sea reservoirs should be similar. Hence, CO_2-EOR projects in the North Sea are likely to require similar CO_2 quantities. Moreover, since the North Sea reservoirs are deeper, this increases the likelihood of achieving miscibility.

The US and Canadian projects are typically managed with a 5 or 9 spot well pattern of closely spaced injection and producer wells. The North Sea fields more typically utilise line drive patterns.

Reservoir modelling performed by BP on Forties [43] and by Statoil on Gullfaks [44] has also confirmed the significant potential that may exist for North Sea reservoirs when exploited by enhanced oil recovery with CO_2 injection. It has been suggested, however, that the recovery potential in the North Sea fields will be lower than those achieved in the USA. For example, predictions for the Gullfaks field are of the order of 5% OOIP. This low oil recovery potential is attributed to unfavourable reservoir characteristics that cause poor sweep efficiency due to early CO_2 breakthrough resulting from differences in mobility, gravitational effects, and reservoir heterogeneity that leads to excessive channelling of the CO_2 into high permeability layers of the reservoir. Although the latter issue is typically addressed by closing wells, this may not be possible offshore due to the smaller number of injection and production wells. Another factor that may affect oil recovery in the North Sea is the reduction of reservoir pressure caused by a decrease in injectivity, leading to a reduction of the MMP. Although this issue can be addressed easily in onshore projects via injection through nearby wells, the spacing of offshore well does not allow for this. A third reason that may result in recovery rates in the North Sea lower than those in the USA is the high efficiency of waterflooding. As already mentioned, CO2-EOR projects have been successful when the remaining reservoir rock saturation with oil after waterflooding is about 60%. Nevertheless, waterflooding in the North Sea has been very effective. The oilfields in the North Sea are expected to have lower oil saturation upon waterflooding. Finally, many North Sea fields have strong aquifer support which could limit the opportunities for pressure management [45], a feature that will have a major impact especially to immiscible displacement projects.

Experience with water injection and the plethora of information on well connectivity accumulated during secondary recovery could be used to help assess the likely timing of incremental oil production using CO_2. Experience with miscible injection in the USA has typically shown there is a delay of 1 to 2 years between CO_2 injection and production of incremental oil. The well spacing is greater however for the North Sea fields. Nevertheless, the injectivity (i.e. the rate at which CO_2 can be injected) is greater in the North Sea, which is believed to counterbalance the effect of larger well spacing, in terms of time lapse between CO_2 injection and incremental oil production. A longer delay would however be expected for immiscible displacement schemes, and this would need to be factored into commercial decisions on implementation.

Although pilots are typically managed in the USA before full implementation in oilfields, the lack of low cost CO_2 and the need for modification to oilfield installations may make the operation of pilots in the North Sea prohibitive. Once initial CO_2-EOR projects are operating, it may be easier to source CO_2 for pilots.

In conclusion, detailed field-specific reservoir modelling will be required prior to implementation. Each candidate reservoir should be studied in detail to assess the efficiency and optimal design of the project. Finally, pilots may be managed before full implementation, however, deploying pilot projects offshore may be uneconomic.

3.5.2 CO_2 - reservoir interactions

Despite the gained experience, the chemical and physical interactions between the injected CO_2 and the reservoir rock and its contents have not been well understood. This has an impact on the management of the project and the quality of oil recovered.

Impact on project efficiency

The efficiency of a CO_2-EOR project can suffer from scale formation in the producer wells through deposition of contaminants that are present in the produced CO_2/water/oil mixture. In the project of the carbonate Dollarhide Devonian unit, scale formation in the producer wells was initially caused by deposition of leached calcium sulphate from the carbonate reservoir, followed by deposition of leached calcium carbonate and then by heavy asphaltenes which were present in the crude oil.

CO_2 injection can make scaling through calcium carbonate worse, as there is a greater concentration of bicarbonate ions in the water from the producer wells causing the deposition of calcite deposits in the pores and on the sides of the tubing as the pressure drops.Also, when high pressure CO_2 reaches the production wells it can expand. The resulting cooling can lead to increased deposition of asphaltenes in the production wells reducing injectivity. The effects are reservoir specific, depending on reservoir and well temperatures and pressures.

However there is significant international experience on the use of inhibitors to effectively deal with scaling problems should they arise. Also, due to the small number of carbonate reservoirs in the North Sea, scaling from calcium carbonate should not be significant.

On the other hand, in some formations, the injected CO_2 also will dissolve minerals increasing the permeability in sandstones. It is claimed that if dissolution is severe, channels will be created affecting sweep efficiency both on the micro and the macro level, with unpredictable effects in the overall efficiency of the project. This is important for sandstones, because these minerals contribute to the cementation of the rock.

Impact on oil quality

It is reported that a miscible displacement process will tend to produce a lighter crude than the original crude in the reservoir. It has also been suggested that the injection of CO_2 may increase the sulphur content of oil. This depends on the levels of sulphur contained in the injected CO_2. The SACROC unit in West Texas utilises some CO_2 for EOR that has been captured from natural gas processing plants. This is sour CO_2, containing around 2% sulphur. Similarly the CO_2 captured from the Dakota Gasification Plant, which is used at Weyburn, contains around 0.9% hydrogen sulphide. Although there is no threshold limit, use of such impure CO_2 may increase the sulphur content in the produced oil.

However, it is possible to design new CO_2 capture plant to provide low levels of sulphur in the CO_2. Coal typically contains 0.6-2.5% sulphur. In a coal IGCC plant, a two stage physical solvent process can be used to remove any H_2S in the gas. The first stage can remove over 99.5% of the sulphur, and the second stage can be used to

capture high purity CO_2. If this high purity CO_2 is used for CO_2-EOR, then there is no increase in the sulphur content of the produced oil through impurities in the injected CO_2.

3.5.3 Economics – Capture, transport, injection and processing infrastructure for CO_2

The availability of low-cost CO_2 in sufficient quantities has been the most important barrier to the implementation of CO_2-EOR in Europe. As mentioned earlier, due to the lack of natural reservoirs in the vicinity of the European oil-producing regions[22], CO_2 needs to be captured from nearby anthropogenic sources such as power plants. The economics of CO_2 capture have been discussed in detail elsewhere [4].

There is very significant international experience of transporting CO_2 over large distances by pipeline. West Texas has 3900 km of an integrated CO_2 pipeline infrastructure, which delivered over 25 million tonnes of CO_2 in 2003. The pipeline material used is carbon steel, and internal pipe corrosion has been managed through the low amount of water permitted in the CO_2 specification (less than 0.5g / Nm^3 CO_2). Offshore pipeline transport of CO_2 will require that the pipelines be protected from external corrosion by the marine environment. However, there is already much successful experience in the North Sea of pipeline coating technologies that prevent marine corrosion.

Although CO_2-EOR projects can benefit from significant additional oil sales and CO_2 credits, they often require 3-5 years to pay off, due to the capital investment but more importantly due to the operating costs. According to [32] 50% of the additional oil production costs refer to CO_2 purchase, 37% account for operating costs and just 13% for capital charges.

The largest contributor to operating expenses is electric power, needed for driving the producer pumps as well as for CO_2 separation, recompression and re-injection in the wells [35]. On average 4 kW of electric power is required per barrel of oil per day extracted from CO_2-EOR projects, which is 5 times higher than for thermal EOR.

A major issue of handling CO_2 is that of corrosion of iron infrastructure. CO_2 – induced corrosion will need to be managed once the CO_2 reaches the injection well, as CO_2 dissolves in water to produce carbonic acid. Carbonic acid is corrosive to carbon steels. Hence the bottom of the injector wells, and the casing and tubing that form the annular producer wells are potentially liable to corrosion. It has been claimed that it would be a cheaper option to build new platforms than to modify existing ones so that they become compatible to CO_2 use [41]. Some wells in the North Sea are already designed to manage the effects of CO_2 corrosion, as some of the oilfields naturally contain significant quantities of CO_2. In West Texas, CO_2 corrosion is managed by utilisation of a polyethylene lining in the tubing. The annulus between the casing and tubing is also filled with an inhibitor fluid, which typically has reduced the effects of corrosion to less than 2.5 micrometers per year. The surface structures are usually

[22] An assessment of the European natural CO_2 reservoirs has been performed in the frame of the NASCENT project (Natural analogues to the storage of CO_2 in the geological environment) co-funded by the European Commission.

lined with an epoxy or fibreglass coating. Stainless steel manifolds are also used to collect the produced oil/CO_2/water mixture.

The optimum detailed implementation of each project will be very field-specific, and detailed design studies will be necessary to give confidence in the cost of modifying wells and topside structures. Hence there is a large uncertainty in the capital costs associated with specific field deployment at this stage. In some instances it may be concluded that implementation would be most cost effective through use of new platforms in the North Sea. More recently developed North Sea fields have deployed FPSO (floating production storage and offtake) vessels. It might be possible to provide some flexibility in EOR deployment in the North Sea through the utilisation of such vessels, which would be specifically designed for CO_2-EOR operations.

3.5.4 Economics - Difficulties of offshore operations

The additional difficulty in working offshore, where space and weight are major limitations, is reflected in the higher costs of implementation, compared with onshore deployment. Higher costs will incur for offshore pipelines and for the provision of new topside processing structures. For example, the specific capital investment for offshore compressors is 500 € per m^3/d output. Design of CO_2/water/hydrocarbon separation plant will need to reflect the fact that space is at a premium on North Sea rigs. The deployment of such infrastructure can benefit from the experience gained in the USA where compact plants are used, such as membrane separators.

Despite the difficulties of working offshore, there is now significant international experience of offshore oilfield operations, including the more challenging deepwater environments such as the Gulf of Mexico. Offshore operation has not prevented high quality operations during the secondary recovery phase. However the logistics of implementation in the North Sea would be significantly more complex than for onshore deployment.

3.5.5 Economics - Urgency of deployment

A major issue for the implementation success of CO_2-EOR projects is their timely deployment.

Although it is difficult to assess precisely when a field will cease production within the production tail it is clear that for many fields, decisions on EOR need to be taken over the next ten years, or else the alternative is abandonment.

The well pattern required for a miscible displacement project might be similar to that deployed for water injection, hence the appropriate time for deployment is any time during the tail end of secondary production. It would be difficult to re-enter a field after abandonment to effectively implement an EOR project. Hence the next decade provides the best opportunity for implementing an EOR programme in the North Sea, extending field life and recovering oil that would otherwise be abandoned.

Immiscible displacement projects are more likely to be deployed at the end of secondary recovery, as the well pattern deployed is substantially different from that used in secondary recovery.

A large commercial potential benefit for undertaking EOR is the deferment of the significant expense of decommissioning, particularly the large steel platforms. A factor that will be taken into account in determining the decommissioning date is the status of the satellite fields that have also been developed. These satellite fields tend to be smaller than the main field, and also deplete faster. As the North Sea province becomes more mature, there becomes less scope for development of additional satellite fields to sustain a viable level of oil production from the platform, and hence deployment of tertiary recovery will become a more significant option for achieving substantial deferral to the decommissioning date.

3.5.6 Non Techno-economic Issues

The successful deployment of CO_2-EOR does not solely depend on improving the economics, solving engineering problems and clarifying related technical aspects. Legal / regulatory implications, public perception and commercial issues could play a very important role, to the extent that they could be the decisive factors for the implementation of the technique. These non techno-economic issues are discussed next.

Legal Implications

This section highlights the legal issues related to the use of CO_2 in EOR operations. Although the focus in this report has been the injection of CO_2 in oil reservoirs for the purpose of increasing oil recovery, the implications for using the technique for storing CO_2 in the oil reservoir, either by maximing CO_2 retention underground during oil recovery, or by just continuing CO_2 injection even after the end of oil production for storage purposes should not be overlooked; especially since CO_2-EOR has been considered as a possible means for reducing GHG emissions. This report does not attempt to interpret legislation, as this is already under examination by more competent bodies, but rather to give an overview of conventions and regulations in place that may have an influence on the subject.

Currently, there is no legislation in force in Europe prepared specifically to tackle the issues related to CO_2 injection underground onshore. Furthermore, national and international law, applicable to European countries, is relevant to the operation of CO_2-EOR projects under the European seabed. It is noted however that these laws were not prepared to address the issue of CO_2 injection either for EOR or for storage but to prohibit dumping at sea.

A review of pertinent documentation suggests that there are no legal barriers for the use of CO_2 in EOR projects. Legal uncertainties, however, surround the injection of CO_2 underground for storage purposes. These legal issues may hinder the CO_2 injection in oil reservoirs when this is not associated with a simultaneous oil recovery. This will reduce significantly the possibility for realising the CO_2 storage capacity potential in oil reservoirs. In extreme cases, this could also delay EOR projects if their operation is aimed at maximising the amount of CO_2 injected. These projects may be perceived as serving a different purpose than that of EOR and conventions and legislation may be interpreted unfavourably for the implementation of such projects.

There is a general consensus that the use of CO_2 in offshore EOR projects in the North Sea is exempt from the provisions of the OSPAR Convention. The 1992 OSPAR Convention for the protection of the marine environment of the northeast Atlantic[23] prohibits *"... the introduction by man, directly or indirectly, of substances or energy into the maritime area[24] which results, or is likely to result, in hazards to human health, harm to living resources and marine ecosystems, ..."*[25] including from inland sources, mentioning explicitly the use of pipelines. A report from the Group of Jurists and Linguists [50] of the OSPAR Commission has expressed an initial view on the issue suggesting that any '*placement*'[26] of CO_2 from an offshore installation, arising from either offshore or onshore activities for the purpose of *genuinely* facilitating or improving the production of oil and gas is not prohibited but is subject to the provisions of the Convention and authorisation or regulation respectively. However, the placement of CO_2 for the purpose of mitigating the effects of climate change is prohibited.

Further regulatory issues concerning the offshore usage of CO_2 are governed by conventions regarding marine pollution (such as the London Convention) since CO_2 could cause pollution and damage to the environment if leaked. The London Convention on the prevention of marine pollution by dumping of wastes and other matter, signed in 1972, and its 1996 Protocol[27] although not yet in force, are relevant when considering the storage of CO_2 in geological structures beneath the sea as they have provisions prohibiting the dumping of industrial waste[28] in the oceans without authorisation by national authorities, with certain exceptions. The London Convention applies to ships, aircraft and offshore platforms, the latter with the exception of (i) the disposal of wastes or other matter directly arising from, or related to the exploration, exploitation and associated offshore processing of sea-bed mineral resources and (ii) placement of matter for a purpose other than the mere disposal thereof, which are not covered by the provisions of this Convention. While the Sleipner project falls into the first exemption, EOR projects fall in the second exemption, since CO_2 is used for oil production rather than for storage.

Another legal uncertainty refers to the right to use underground formations for CO_2 storage and whether this right resides solely with the sovereign state. This issue falls under the UN Convention of the Law of the Sea (UNCLOS)[29]. According to [46], Article 56 of the Convention "*Rights, jurisdiction and duties of the coastal State in the exclusive economic zone*" and Article 77 "*Rights of the coastal State over the continental shelf*" indicate that the coastal state has sovereign and exclusive rights for

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[23] For the full text see the Official Journal, L 104,03/04/1998, p.2-21.

[24] "Maritime area" means the internal waters and the territorial seas of the Contracting Parties, the sea beyond and adjacent to the territorial sea under the jurisdiction of the coastal State to the extent recognised by international law, and the high seas, including the bed of all those waters and its subsoil, situated within well-specified limits in North-eastern Atlantic.

[25] Article 1.d. of the Convention.

[26] 'Placement' is used in the specific document to cover all forms of deliberate introduction of CO_2 into the marine environment by whatever method and for whatever purpose.

[27] The Protocol clarifies that the term 'ocean' includes water masses, the seabed and the subsurface.

[28] Industrial waste is defined as generated by manufacturing or processing applications.

[29] For more information: www.un.org/Depts/los/index.htm

the use of these formations on the condition that these do not stretch across the borders of the continental shelf of neighbouring countries. In the latter case the decision cannot be taken unilaterally and an agreement should be reached between the States involved.

Furthermore, the legal terrain of injecting CO_2 in oilfields onshore in Europe is unmapped. National laws have jurisdiction and require an ecological impact study, approval of well designs and operational procedures, etc., before authorities grant a permit in order to allow this activity. However, the current state of scientific certainty regarding carbon storage may not be sufficient to meet this burden of proof, hence there is a need for continued research and monitoring. The injection of CO_2 in oil reservoirs, mainly for storage, should be compatible with the existing national legislation, and in accordance with European Directives, such as those on dumping waste materials (1999/31/EC) and on water (2000/60/EC).

Further legislation regulating CO_2 injection underground may be necessary to provide a robust framework to support the possible implementation of CO_2-EOR on a large scale. Foremost, regulation will have to address the health, environmental and safety risks on a local/regional level associated with the implementation of the technique. Thus, legislation will have to (i) set regulations rules and standards that ensure safety and the minimisation of other adverse impacts of CO_2-EOR, and (ii) define performance standards for monitoring and verification to ensure that acceptable risk levels are not exceeded. In addition, legislation may be invited to go one step further, to reduce the global risk of re-accumulation of CO_2 in the atmosphere related with the (in-) effectiveness of the process as a carbon mitigation tool. Equally important, the issues of eligibility of CO_2-EOR projects for financial benefits arising from CO_2 retention underground needs to be resolved.

Public Perception

History has shown that the public can become fearful when a new technology is deployed without the associated risks and impact been thoroughly explained, and sceptical when it feels excluded from the decision making process. It is not rare to see cases where obstacles set by the public are more difficult to overcome than technological and economic barriers, which may ultimately stop the deployment of an otherwise economically and technologically viable technology. To this extent, and given the increased sensitivity of the public over issues related with the environment and climate change during the recent years, it is expected that carbon capture and storage will be severely scrutinised by environmental groups and the public at large. This may also affect the deployment of CO_2-EOR projects.

Though there are no reports available of large-scale public opinion studies on CO_2-EOR, there is some previous work done on the reactions of different population groups and stakeholders to carbon capture and storage. While the studies are mostly confined to national level, like those performed by the Tyndall Centre for the UK [54, 55] and Lenstra and Van Engelenburg [56] and the CRUST project [57] for the Netherlands, there is also work looking at a more global perspective [58]. Though the findings cannot be considered representative due to the small size of the groups taking part in the studies, they provide an indication of the public perception towards the subject.

What transpires is that the reactions vary, depending on the background of the stakeholders and the origin or type of the project involving CO_2 storage. It is questionable whether the public will receive carbon storage via EOR positively as a useful instrument to combat climate change, or rather consider it as a controversial option with high associated risks, negative impact to the environment and doubtful effectiveness. There are indications that the public is more positive towards carbon capture and storage options, which 'utilise' CO_2 in some way and are connected to already demonstrated technology in practice, such as EOR. A negative opinion may be fuelled by little or no awareness among the environmental groups and the general public, the lack of consensus among the scientific community about the benefits and implications of the option, and the existence of major knowledge gaps that currently hamper carbon capture and storage.

Given that environmental groups strongly support other certainly more effective carbon management options, such as the use of renewable energy and energy efficiency, carbon capture and storage may be perceived as a 'ploy' to continue using and investing in fossil fuels, thus deviating attention and funds from other carbon management options and causing delays in real reductions of emissions. Furthermore, the '*disposal of*' emissions may be negatively perceived in principle, and may be used to tag CO_2-EOR as a non-clean and non-sustainable technological option, more like an 'end of pipe' treatment of the symptoms rather than a real solution to the causes. Unless there is a robust proof that CO_2 leakage from geological storage sites is negligible and safe and does not create a burden to future generations, public will demand assurances about the safety of carbon storage and may not allow for storage operations to function. To this end, ongoing demonstration projects, such as Sleipner, have produced encouraging results.

The position of environmental groups is also varied, from support and keeping an open mind to scepticism, concern and opposition to what may be an excuse to continue 'business as usual'. They suggest [59, 60] that carbon capture and storage via EOR would be welcome only if it is a part of a sound strategy that accelerates the penetration of renewable energy sources and improves energy efficiency. The role of CO_2-EOR in this strategy would be complementary to other carbon management options, aiming to offer deeper emissions reductions in the short to medium term, until the other carbon management options start producing results. However, the development of a rigorous research, development and demonstration program that would be capable of providing robust answers to questions regarding safety, effectiveness and impact to the environment and the ecosystem would be a prerequisite. Finally, the development of a public outreach program would be imperative to inform and have the public involved.

3.5.7 Commercial Issues

Commercial conflicts may impede the implementation of CO_2-EOR projects. Transferring ownership from a petroleum rights holder to a CO_2 storage rights holder at the end of the oil recovery operation has been untested and is undoubtedly a complex procedure [30]. So far however, CO_2-EOR has not proved controversial in the USA and Canada.

CO_2-EOR projects are ventures that require a large capital investment upfront, possibly with the involvement of several interested parties (oil companies, power companies, pipeline operators etc.), which are then tied to this commitment and dependent on the actions of each other for a long period of time. With the inherent risk of such projects, good organisation and planning to allow for a degree of flexibility and future alternate uses of the infrastructure may have value in terms of attracting investors. In contrast, uncertainty on the issue of eligibility of CO_2-EOR projects to participate in CO_2 trading schemes may discourage such ventures, especially since there is a limited time frame available for their realisation due to the urgency of EOR implementation in the North Sea oilfields. As long as these issues are not resolved the oil companies may opt for EOR methods that are less controversial than CO_2-EOR [46].

3.5.8 Summary

The key issues that may hinder the implementation of CO_2-EOR in Europe are:

- ***Technical***
  - Non-optimal geological structure of the reservoirs, especially in the North Sea, that may result in lower oil recovery rates than those achieved in North America. Detailed field-specific reservoir modelling will be required prior to project implementation.
  - Lack of CO_2 supply in the absence of natural CO_2 reservoirs. The supply of anthropogenic CO_2 will benefit significantly from advances in carbon capture technologies.
  - Challenging operating conditions in offshore recovery projects, related to the number of existing wells and their spatial distribution.
  - Corrosion of some of the infrastructure in place, not initially designed for CO_2 use.
  - Lack of experience with immiscible projects
- ***Economic***
  - Increased operating costs, mainly due to the purchase of CO_2
  - Increased capital expenses for the modification of the existing infrastructure, the purchase and installation of additional equipment (such as CO_2 compressors and separation membranes) and possibly the construction of new platforms and wells. These expenses are higher for offshore applications, where space in oilrigs is at premium and the cost of drilling is significantly higher than onshore.
  - Capital and operating expenses for the construction and operation of a CO_2 pipeline network
  - Lack of financial incentives for CO_2 storage (e.g. eligibility for participation to emissions trading, carbon tax, etc.)
  - A limited window of opportunity for implementation, since CO_2-EOR projects should commence at about the cessation of conventional oil recovery processes. Currently, many oilfields in the North Sea approach end of operations, and hence, decisions concerning the initiation of CO_2-EOR projects should be made in the short term.

- ***Environmental / Public acceptance***
  - Environmental concerns for the permanence and safety of CO_2 storage in the oilfields. These concerns may affect public acceptance in disfavour of CO_2-EOR. Ongoing demonstration projects on geological storage have been providing useful information on this issue.
- ***Legal***
  - Uncertainty surrounding the legal frame for the storage of CO_2 underground.
- ***Organisational***
  - Need for coordination and agreement between CO_2 suppliers (e.g. power plant owners), CO_2 pipeline operators and oil producers for the execution of projects

3.6 Needs for Further Research and Development

There are no major technical challenges in onshore CO_2-EOR projects. Nevertheless, CO_2-EOR will benefit from advances in science and technology in the areas of carbon capture and storage and that of oil exploration. Further research and more importantly development are however needed in specific areas to facilitate the large-scale implementation of CO_2-EOR in Europe [30, 47]:

- Methods for determining the distribution of petrophysical properties for use in geological models
- Improved reservoir monitoring using 4-D (time lapse) seismic surveillance
- Advanced geochemical models to account for the complex phase behaviour and compositional changes of reservoir components
- Advanced reservoir simulations using reduced data sets and determination of minimum requirements for a credible assessment
- Physical / chemical interactions between CO_2, the reservoir and its contents, focusing on:
  - Viscous fingering and compositional instabilities
  - Impact of wettability - capillary pressure
  - pH effects
  - Multi phase relative permeability
- Scale-up of laboratory experiments
- Improvement of injectivity
- Application of immiscible displacement projects in heavy oil reservoirs
- Determination of degradation characteristics of well construction materials, including well sealing materials
- Methods to verify and monitor CO_2 in the oil reservoir
- Formulation of screening and applicability criteria for CO_2-EOR projects - Development of ‘ best practices’ guidelines

4 Case study: The Implementation of CO_2-EOR in the North Sea

In the context of this report a preliminary assessment was performed to identify the potential for CO_2-EOR projects in the North Sea. This case study is presented in this Chapter. Section 4.1 contains a brief description of the history of oil production in the North Sea, while Section 4.2 provides a summary of the oil fields reviewed for this study. The technical potential for oil recovery and CO_2 storage in the reviewed fields is estimated in Sections 4.3 and 4.4 respectively. However, as discussed previously it is economics that will be the determining factor that will decide how much of this potential could be realised. Section 4.5 includes a simple, preliminary economic assessment for 15 of the reviewed fields which are considered as urgent prospects, as they are at the end of production.

4.1 Oil Production in the North Sea [61]

Oil production in the North Sea commenced in 1971 from the Ekofisk field in the Norwegian Sector and in 1975 from the Forties field in the UK Sector. During the last thirty years, the North Sea has been an important and successful oil-producing province. In 2003, the oil production from the core area of the North Sea reached 200 million tonnes, which accounted for around 6% of global conventional oil production.

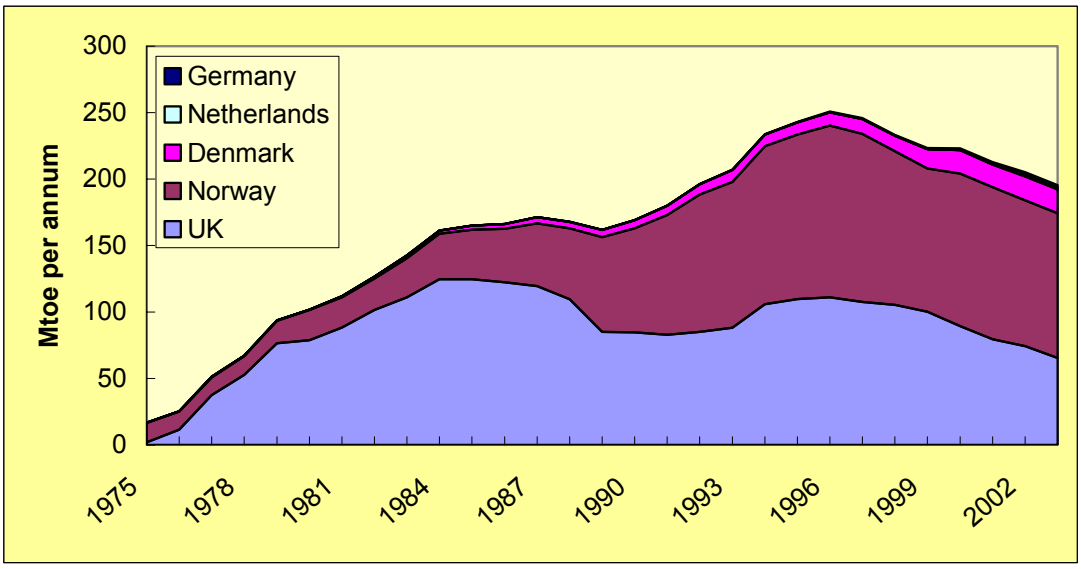

Figure 4.1: Oil production history in the North Sea per sector

Figure 4.1 shows oil production in the core area of the North Sea, excluding the areas West of Shetland and the Norwegian Sea. The North Sea is now a very mature oil province. Oil production peaked around 1996 and has been slowly declining thereafter. The North Sea has been extensively explored, and the vast majority of the oil discoveries were made in the period between 1970 and 1990. There have only been occasional significant exploration successes since 1990, such as the case of the

discovery of the Buzzard field in the Moray Firth in 2001, with estimated reserves in excess of 400 million barrels.

Figure 4.2 shows that the UK sector of the North Sea has followed the typical pattern for exploitation of an oil province. The large fields, such as Forties and Brent were developed first. As production from the larger fields declined, production has been maintained through the development of a large number of smaller satellite fields, which in general utilise much of the initial infrastructure. However, these smaller satellite fields usually have a shorter lifetime than the larger fields that were developed first, which has led to a steep decline in production from the core North Sea areas since around 1996. The decrease in production between 1989 and 1993 was partly due to the impact of the accident on the Piper Alpha platform in 1988. The typical expected ultimate oil recovery from the best UK reservoirs after water-flooding is around 45%, and might increase by 10% by EOR [63].

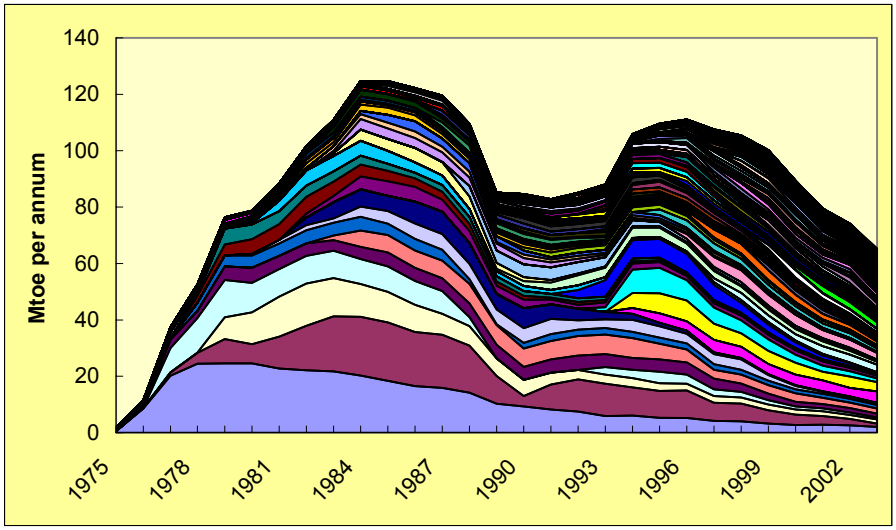

Figure 4.2 : North Sea oil production, UK sector excluding West of Shetland. Different colours represent different fields.

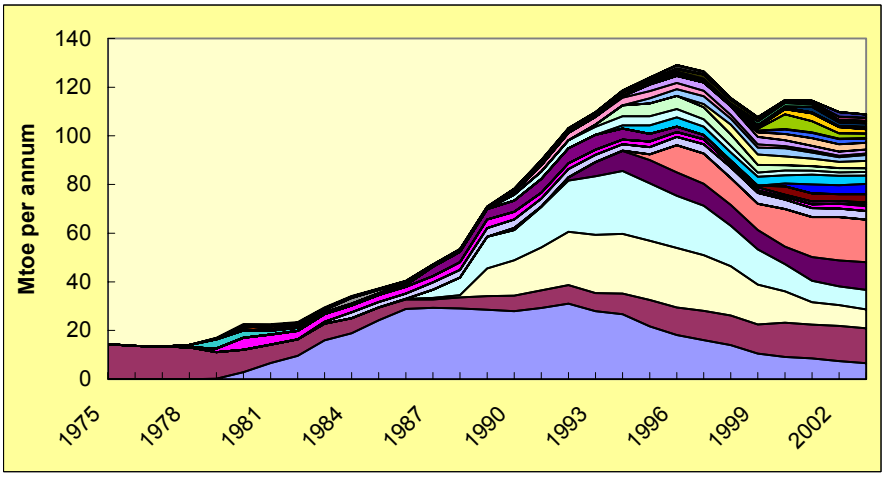

Figure 4.3: North Sea oil production, Norwegian sector excluding Norwegian Sea. Different colours represent different fields.

Figure 4.3 shows a similar pattern for the Norwegian Sector, which is generally not as mature as the UK Sector. Production is dominated by the six largest fields, Statfjord, Ekofisk, Oseberg, Gullfaks, Snorre and Troll. Production from the Norwegian sector is currently being sustained at a greater level than from the UK sector. The overall oil recovery factor on the Norwegian continental shelf is now 46% [64].

Figure 4.4 shows that although production from the Danish Sector is not yet declining, the overall level of production is significantly smaller than for the UK and Norwegian sectors.

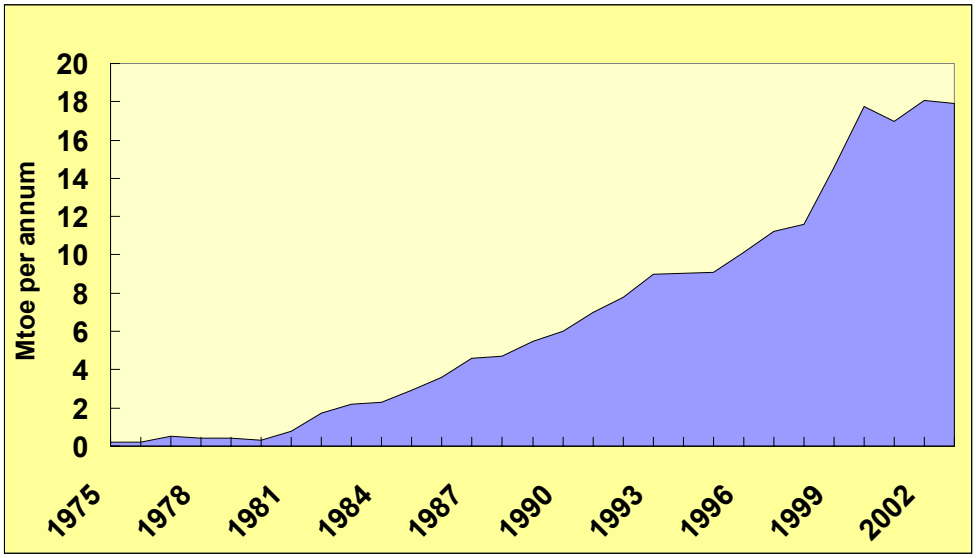

Figure 4.4: North Sea Oil Production, Danish Sector.

4.2 Review of oilfields

A total of 81 oil fields (shown in Figure 4.5) in the North Sea were considered in this case study taking into consideration data of oil reserves, production history, reservoir and oil parameters and field infrastructure in order to assess the potential for CO_2-EOR applications [61]. The oilfields reviewed in this study are in the core area of the North Sea. Oilfields in the other oil producing areas to the West of Shetland, in the Irish and Norwegian Seas and onshore, as well as major gas condensate fields were excluded from the analysis.

It is stressed that this is a preliminary assessment and not a detailed modelling study, which would have to be performed for each field for a complete feasibility assessment. Therefore any figures presented here are merely observations related to field statistics and readily available data, on a theoretical basis and they should be revisited through specifically targeted reservoir models in order to confirm their applicability in practical terms.

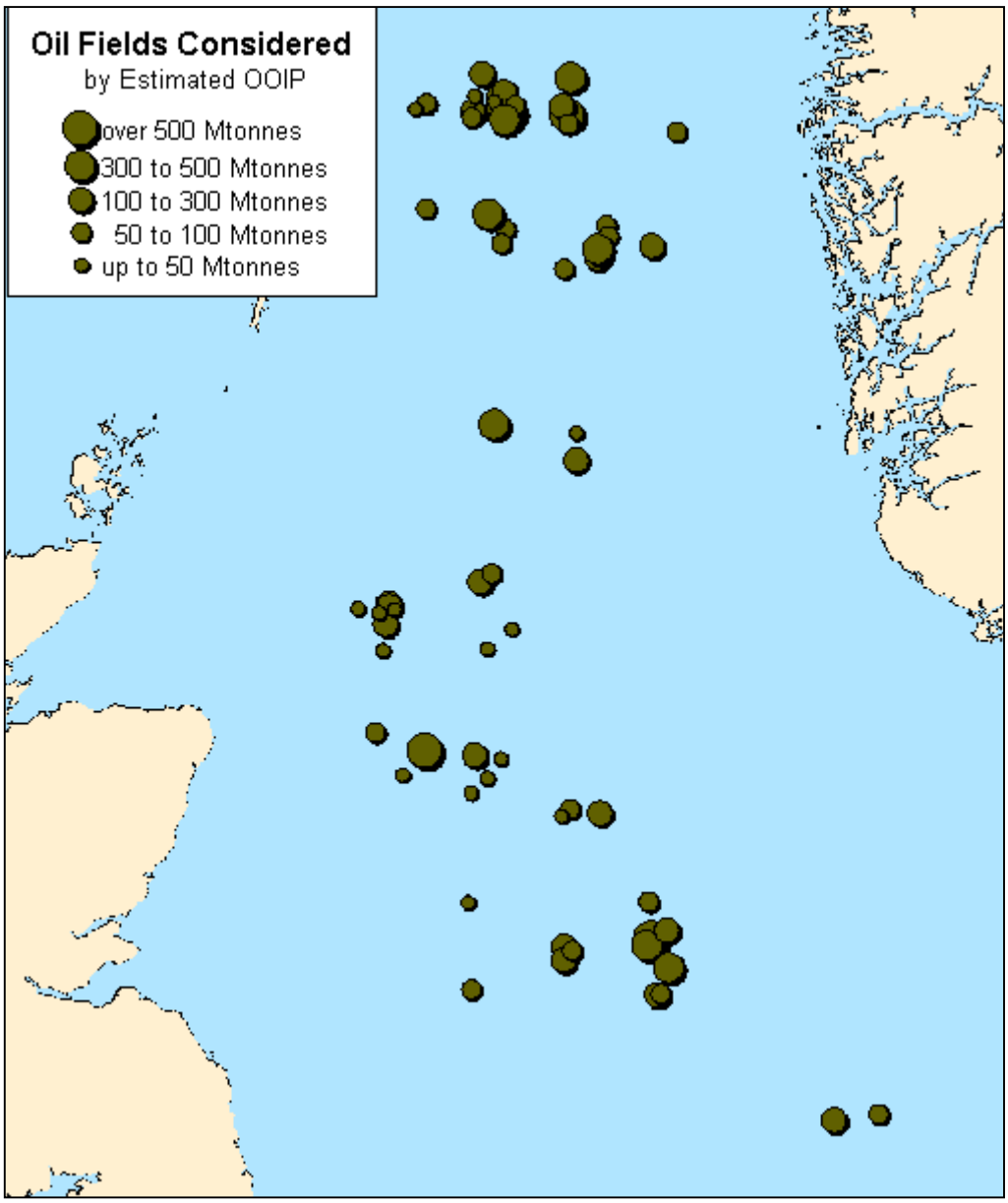

Figure 4.5: Oil fields considered in the North Sea

Based on an initial screening, major oilfields in the UK, Norwegian and Danish sectors of the North Sea that would be capable of accepting the volumes of CO_2 which could be captured from anthropogenic sources, were grouped in the following categories:

- Large operational oilfields suitable for miscible displacement projects (59 fields)
- Large operational oilfields suitable for immiscible displacement projects (16 fields)
- Operational heavy oilfields that have viscous oil with less than 22 API, which are therefore less suited for CO_2-EOR. They were not considered further in the analysis (6 fields).

- Major oilfields where production has already ceased, not considered further in the analysis.
- Smaller fields with recoverable oil reserves of less than 10 million tonnes, not considered further in the analysis (92 fields).

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The classification of fields as potentially being suited to miscible or immiscible CO_2 displacement is very preliminary. The potential for miscible injection has been assessed mainly from the point of view of exceeding the Minimum Miscibility Pressure. However, a more detailed field evaluation would be required for a more definitive assessment of the most appropriate technique to be deployed in a specific field.

4.3 Estimation of the resources technically recoverable by CO_2-EOR

CO_2 projects can be designed to either minimise CO_2 utilisation or to maximise CO_2 storage. In the absence of any economic benefits from geological storage of CO_2, the purchase cost of CO_2 is the dominant cost, hence the objective is to buy as little CO_2 as possible at the field and maximise the potential for CO_2 recovery and recycling. This is the most likely approach to be adopted without benefits from emissions trading. The CO_2 quantities required have been calculated in this section on this basis.

Both the classification of fields as miscible or immiscible projects and the estimation of the potential oil recovery through CO_2-EOR are based on information on the present status of the fields. The fact that they are still in operation and will probably be producing oil by the time CO_2-EOR plans are implemented could mean that these estimates may have to be revisited. For example, Statfjord now classed as a miscible project, will start blow down in 2007 and can therefore not be a candidate for immiscible CO_2 injection before 2018, while Oseberg, another immiscible candidate cannot be considered for CO_2 injection before 2025 at the earliest, due to large sales of gas volumes. Oil recovery for both fields will be over 60% by then [65]. Similar circumstances may be applicable for more of the fields mentioned below. The individual production history and expected oil recovery rate are issues worth considering in more detailed future studies. It was however considered that they were outside the scope of the present study.

4.3.1 Miscible CO_2 displacement opportunities

Based on the discussion in the previous Chapter two cases for the oil recovery factors have been considered. In a ‘high’ oil recovery scenario on average 9% of the OOIP is assumed to be recoverable during EOR, provided that the MMP is exceeded. This is in accordance to the US experience. In a ‘low’ oil recovery rate case, only 4% of the OOIP is recoverable, in line with the reservoir modelling exercises performed in North Sea reservoirs, as discussed in the previous Chapter. Furthermore, efficient CO_2 displacement projects designed to maximise incremental oil recovery typically require 0.33 tonnes CO_2 to provide an incremental barrel of oil, which is also the value adopted for the following calculations regardless of the incremental oil recovery rate assumed.

The CO_2 required for a miscible CO_2-EOR project was calculated as follows:

The Original Oil in Place (OOIP) was multiplied by the estimated recovery factor during CO_2-EOR (herein assumed 9% and 4% for the two respective cases). The resulting estimation of incremental oil production in barrels was multiplied by the CO_2 requirement estimate per barrel (herein assumed 0.33 tonnes CO_2 per barrel of incremental oil produced). Conversion from tonnes of oil to oil barrels, where necessary, is done by assuming 7.5 barrels to the tonne.

$CO_{2Req.}$= OOIP [M bbl] x 0.09 (or 0.04) x 0.33 [t CO_2/ bbl]

Table 4.1 and Table 4.2 show the estimates for the technically recoverable resources and indicative CO_2 utilisation aggregated per sector and project urgency for an incremental recovery rate of 9% and 4% respectively. A project is considered urgent when the oilfield is over 80% depleted with regards to the estimated recoverable oil reserves at the projected end of secondary recovery(based on 2003 production data).

Table 4.1: Potential for increased oil recovery and CO_2 storage per sector in miscible displacement projects. Assumed incremental oil recovery at 9% of OOIP.

Sector	*Depleted > 80%*	*Number of Fields*	*Estimated OOIP M bbl*	*EOR Potential M bbl*	*CO_2 Required Mt*
UK	Yes	27	21615	1943	650
UK	No	8	3825	345	116
NO	Yes	5	11730	1058	352
NO	No	14	22493	2025	675
DK	Yes	2	1643	150	49
DK	No	3	3863	345	116
Subtotal	Yes	34	34988	3150	1051
	No	25	30180	2715	907
Total		59	65168	5865	1958

For the UK Sector the total miscible displacement potential is assessed, on the basis of a 9% incremental recovery rate, to be approximately 2300 million barrels of incremental oil, which is 35% of the remaining proven and probable oil reserves in the UK sector (December 2003 estimate). A high proportion of these fields are currently in the late stages of secondary recovery. If a low recovery rate of 4% is assumed then the estimate drops to approximately 1000 million barrels or the equivalent of 15% of the proven and probable remaining oil reserves.

A screening, for the DTI, of the most significant fields has found that WAG could be applicable in 60 reservoirs producing 300-750 million incremental barrels of oil and sequestrating 50-250 million tonnes of CO2 in the process [63]. Although that study was recently updated (and so was the data quoted here) it was initially performed in

the early 1990's and it is possible that more reservoirs could now be deemed suitable for the technique.

Table 4.2: Potential for increased oil recovery and CO_2 storage per sector in miscible displacement projects. Assumed incremental oil recovery at 4% of OOIP.

Sector	*Depleted > 80%*	*Number of Fields*	*Estimated OOIP M bbl*	*EOR Potential M bbl*	*CO_2 Required Mt*
UK	Yes	27	21615	865	289
UK	No	8	3825	153	52
NO	Yes	5	11730	469	156
NO	No	14	22493	899	300
DK	Yes	2	1643	66	22
DK	No	3	3863	155	52
Subtotal	Yes	34	34988	1400	467
	No	25	30180	1206	403
Total		59	65168	2606	870

The Norwegian sector also shows significant potential for CO_2-EOR but the majority of the fields reviewed are not as depleted as the majority of the fields in the UK sector and therefore there are not many fields classified as urgent.

An assessment of 18 Norwegian oil fields in the North Sea [66] estimated the potential incremental oil production from CO_2 injection at a range of 2107 – 2535 million barrels (280 –340 million tonnes). During the process 1115 – 1486 million tonnes of CO_2 would be stored, however only between 41 and 55% would be stored in the oil reservoirs while the remaining would be injected into aquifers. Furthermore a recent study by the NPD [74] estimates the potential for incremental oil recovery from 20 fields to be in the area of 1900 million barrels. This potential is given as a function of the project start date; it becomes 1600 million barrels for projects initiated between 2005 and 2010 and is gradually reduced after 2020. The estimated CO_2 requirement for this incremental oil production is quoted between 500 and 750 million tonnes.

4.3.2 Immiscible CO_2 displacement opportunities

Based on the discussion in the previous Chapter two figures for recovery of incremental oil, in addition to that produced after primary and secondary recovery, were used in this assessment. The first assumes incremental recovery of 18% of the OOIP, while a low recovery scenario sets this figure to 10% of the OOIP. Suitable fields have typically not been subject to extensive secondary water flooding and contain a gas cap or significant quantities of associated gas.

For pressure maintenance using immiscible displacement, it has been assumed that the volume once occupied by oil and gas in the reservoir, extracted during water flooding is replaced by CO_2 until the original reservoir pressure is restored. This is likely to exceed the MMP in some North Sea fields, and there may be scope for reducing the pressure and associated CO_2 requirement to improve the economics of a project. The volume to be replaced refers to oil extracted before EOR and therefore the CO_2 requirement is independent of the incremental recovery rate assumed. The CO_2-EOR potential and the required CO_2 was calculated as follows:

The Original Oil in Place (OOIP) was multiplied by the estimated recovery factor during CO_2-EOR (herein assumed 18% and 10% for the two cases). Then the CO_2 required was calculated from the oil and gas quantities produced after taking into account the reservoir conditions, assuming that a unit volume of CO_2 physically replaces a unit volume of oil or gas.

EOR potential [M bbl]= OOIP [M bbl] x 0.18 (or 0.1)

$CO_{2\ \text{required to replace oil}}$ [Mt]= V_{oil} [M m^3] x CO_2 density [t/m^3] x FVF

$CO_{2\ \text{required to replace gas}}$ [Mt]= V_{gas} [M m^3] x CO_2 density [t/m^3] / GEF

$CO_{2\ \text{total}} = CO_{2\ \text{required to replace oil}} + CO_{2\ \text{required to replace gas}}$

Where:

- V_{oil} is the volume of oil produced after secondary recovery
- V_{gas} is volume of gas produced after secondary recovery
- CO_2 density is at initial reservoir conditions
- FVF is the oil Formation Volume Factor i.e. the volume of oil at reservoir temperatures and pressures, divided by the volume of oil at surface conditions. This is used to correct volumes at the surface to volumes at reservoir conditions
- GEF is the Gas Expansion Factor i.e. the volume of natural gas at surface conditions, divided by the volume of natural gas at reservoir temperatures and pressures. This is used to correct gas volumes at the surface to volumes at reservoir conditions

Table 4.3 shows the estimates for the technically recoverable resources and indicative CO_2 utilisation per sector and according to the project urgency for a recovery rate of 18% of the OOIP. The values in parenthesis refer to the case of the low recovery rate of 10% of the OOIP.

For the UK sector the total immiscible CO_2-EOR potential is assessed on a high incremental oil recovery basis to be around 1400 million barrels of oil. The figure drops to around 750 million barrels when the low incremental oil recovery rate is assumed. A high proportion of these fields are currently in the late stages of secondary recovery. On the other hand, the suitable fields in the Norwegian sector are at an earlier stage in their production history. Immiscible potential in the Norwegian sector ranges from 1400 to 2600 million barrels depending on the incremental oil recovery factor assumed.

The DTI publication referenced previously [63] found 18 reservoirs from 10 fields for which immiscible displacement might be applicable. Incremental oil recovery potential was estimated at 800-1400 million barrels and the CO_2 storage estimate was 400-700 million tonnes.

As discussed in the previous Chapter immiscible displacement projects would generally require a higher amount of injected CO_2 per incremental barrel of oil produced, typically two to three times more. However, values may vary significantly between different fields.

Table 4.3: Potential for increased oil recovery and CO_2 storage per sector in immiscible displacement projects for a recovery rate of 18%. The values in parenthesis refer to a recovery rate of 10%.

Sector	*Depleted > 80%*	*Number of Fields*	*Estimated OOIP M bbl*	*EOR Potential M bbl*	*CO_2 Required Mt*
UK	Yes	5	7403	1335 (741)	1210
UK	No	1	225	38 (23)	24
NO	Yes	2	4568	825 (457)	651
NO	No	8	9743	1763 (978)	1721
Subtotal	Yes	7	11970	2153 (1197)	1861
	No	9	9968	1800 (1001)	1745
Total		16	21938	3953 (2198)	3606

Table 4.4: Total CO_2-EOR potential for increased oil recovery and CO_2 storage per sector. Incremental oil recovery rates for miscible and immiscible projects are at 9% and 18% respectively.

Sector	*Number of Fields*	*Depleted > 80%*	*Estimated OOIP* **M bbl**	*EOR Potential* **M bbl**	*CO_2 Required* **M t**
UK	32	Yes	29018	3279	1860
UK	9	No	4050	385	140
NO	7	Yes	16298	1877	1003
NO	22	No	32235	3782	2396
DK	2	Yes	1643	148	49
DK	3	No	3863	348	116
Subtotal	41	Yes	46958	5304	2912
	34	No	40148	4515	2652
Total	75		87105	9819	5564

Table 4.4 and Table 4.5 give the aggregated potential (miscible and immiscible) for CO_2-EOR in the North Sea fields according to sector and project urgency for the two cases of incremental oil recovery rates assumed. The figures displayed here have been summarised in graphs presented in Chapter 2 in Figure 2.6 for oil and Figure 2.8 for CO_2.

Table 4.5: Total CO_2-EOR potential for increased oil recovery and CO_2 storage per sector. Incremental oil recovery rates for miscible and immiscible projects are at 4% and 10% respectively.

Sector	*Number of Fields*	*Depleted > 80%*	*Estimated OOIP* M bbl	*EOR Potential* M bbl	*CO_2 Required* M t
UK	32	Yes	29018	1605	1499
UK	9	No	4050	176	76
NO	7	Yes	16298	926	807
NO	22	No	32235	1876	2021
DK	2	Yes	1643	66	22
DK	3	No	3863	155	52
Subtotal	41	Yes	46958	2597	2328
	34	No	40148	2207	2148
Total	75		87105	4804	4476

4.3.3 Heavy Oilfields

The Minimum Miscibility Pressure increases as the oil becomes heavier. For this reason, heavy oilfields with API of less than 22 degrees are not ideally suited to EOR with CO_2 injection. A significant proportion of the remaining oil potential in the UK sector is in heavy oil accumulations, contained in the Mariner, Bressay, and other heavy oil prospects. In this study and are not considered further.

4.3.4 Small Fields

Smaller fields with oil reserves estimated at less than 10 million tonnes (75 million barrels) each are less suited to investment in CO_2-EOR due to the limited potential for recovery of incremental oil. This would make the field operation not profitable as a stand-alone project taking into account that the investment required is substantial. However, a lot of the smaller fields could be profitable as satellite projects if they are in the vicinity of a large CO_2-EOR operation due to economy of scale. The aggregated potential of the smaller fields is displayed in Table 4.6.

Table 4.6: Oil reserves in smaller oil fields (<10 Mt) by sector

Sector	*Number of Fields*	*Estimated Reserves* M bbl
UK	77	2418
NO	5	265
DK	10	250
Total	92	2933

4.4 Estimation of the maximum CO_2 storage potential in the North Sea

4.4.1 Miscible CO_2 displacement projects

As discussed, the most significant cost of CO_2-EOR is that of CO_2 supply at the oilfield. In the absence of financial incentives for CO_2 storage, e.g. via emissions trading, the commercial incentive is to minimise the imports and hence the cost of CO_2 by recovering as much as possible from the injected CO_2 and recycling it in the reservoir.

In this case the storage capacity for miscible displacement projects would be much greater than assessed in the previous sections. Ways to increase CO_2 storage in oil recovery include [67]:

- redesigning the wells to create favourable injection profiles
- optimising water injection towards maximising gas storage
- considering injection to aquifers underlying the oil fields (for the recycled gas or to increase storage capacity)
- repressurising the reservoir after the end of oil production by continuing injection

Recent research claims that a well control process, where wells are shut in according to a gas-to-oil production ratio limit to avoid excess gas circulation, is the best way to obtain both maximum oil recovery and CO_2 storage at the same time [68]. However, another recent paper referring to fields of the UKCS (UK Continental Shelf) reports that shutting off wells on gas breakthrough had limited effect in maximising CO_2 storage. Continuous gas injection or optimised WAG schemes were found to be more effective. In all cases there was significant trade-off in the oil production and consequently in the economic value of the projects when the aim of maximum CO_2 storage was pursued, unless a low oil price and high CO_2 storage credit scenario was assumed [69].

The theoretical maximum storage capacity is assessed below, on the basis developed in the EC Joule II project on “The Underground Storage of Carbon Dioxide” [61].

The CO_2 density for each field, which relates to the storage capacity, was assessed with respect to the initial reservoir pressure and temperature conditions, using the information derived in the Joule II project for the prediction of CO_2 density at reservoir conditions.

In the case of oil fields that have undergone extensive secondary recovery though water injection, the reservoirs are typically water saturated and pressurised at the end of secondary recovery.

For WAG injection, designed for efficient CO_2 utilisation, typical amounts of CO_2 that can be stored at the end of EOR are around 2.5 times the reservoir volume of the incremental oil produced. Given an EOR recovery of 9% of the OOIP for miscible CO_2 injection, this equates to a CO_2 storage volume of around 23% of the OOIP. This is lower than the average oil recovery factor of around 45-50% that is typically achieved after secondary recovery. Greater CO_2 volumes could be potentially stored if the floods were designed to maximise CO_2 storage. The objective would be to replace all the oil that had been produced by CO_2.

Hence, if the project was designed to maximise CO_2 storage, a far higher reservoir volume of the initial oil and gas reserves can be utilised. This could be achieved by using a far higher proportion of CO_2 to water, or pure CO_2 in the injection process. The high level of storage is achieved through all the incremental oil being replaced by CO_2, together with the net water saturation of the reservoir being significantly reduced as it is replaced by CO_2.

The methodology adopted here is to assume that the volume available for CO_2 storage equates to the volume occupied by the initial oil and gas reserves that had been produced after secondary recovery by water injection. The gas is assumed to have been initially present as a gas cap. In comparison to the CO_2 requirement for efficient WAG assessed previously, this will usually give a higher limit to the CO_2 storage potential of the field. Exceptions are fields with poor recovery factors and no gas cap present.

The storage volume is calculated by adding the components relating to the storage volume occupied by the initial oil reserves and the gas cap.

$V\ CO_{2\ \text{oil component}}$ [Mm^3] = Volume of Produced Oil [Mm^3] x FVF

$V\ CO_{2\ \text{gas component}}$ [Mm^3] = Volume of Produced Gas [Mm^3] /GEF

CO_2 [Mt] = ($VCO_{2\ \text{oil component}}$ + $VCO_{2\ \text{gas component}}$) [$Mm^3$] x $CO_{2\ \text{density}}$ [t/m^3]

Where:

- the volume of produced oil and gas is at standard temperature and pressure conditions of 0°C and 1atm.
- all other parameters are as described in paragraph 4.3.2

The results are shown in Table 4.7.

A more detailed evaluation, particularly of the larger fields with significant gas reserves, would be appropriate. Enhanced oil recovery by means of CO_2 injection may reduce the profitability of fields with significant gas reserves, as the produced natural gas will be mixed with CO_2 in large quantities. This means that the gas will either have to be re-injected or go through a cleaning and separation process, which requires

new infrastructure and is energy consuming. In both cases loss of profits from gas sales may be assumed. In the case that the gas in re-injected the potential for CO_2 storage will also be influenced. However, comparison of Table 4.1and Table 4.7 shows that there could be a significant commercial trade off between designing CO_2 projects to maximise CO_2 storage or to minimise CO_2 purchases, if CO_2 storage is valued in emissions trading.

Table 4.7: CO_2 storage potential in miscible displacement projects by sector

Sector	*No. of fields*	*Oil Reserves* M bbl	*Gas Reserves* 10^9 m^3	*CO_2 Storage Oil* Mt	*CO_2 Storage Gas* Mt	*CO_2 Storage Total* Mt
UK	35	12960	99	1819	255	2074
NO	19	18330	369	2739	1054	3793
DK	5	2190	58	293	163	456
Total	59	33480	526	4851	1472	6323

4.4.2 Storage Potential: Immiscible CO_2 displacement

For oilfields that are under-pressurised following secondary recovery, the assumption is that the reservoir is restored to the initial reservoir pressure following CO_2 storage, the volume once occupied by oil and gas being replaced by CO_2 as described in Section 4.3.2. The results are shown in Table 4.8.

Table 4.8: CO_2 storage potential in immiscible EOR projects by sector

Sector	*No. of fields*	*Oil Reserves* M bbl	*Gas Reserves* 10^9 m^3	*CO_2 Storage Oil* Mt	*CO_2 Storage Gas* Mt	*CO_2 Storage Total* Mt
UK	6	3660	232	740	677	1417
NO	10	5445	485	997	1374	2371
Total	16	9105	717	1737	2051	3788

The figures displayed in Table 4.7 and Table 4.8 have been summarised in Figure 2.8 presented in Chapter 2 and compared to the CO_2 stored by applying standard practices.

4.5 Estimation of the economically feasible potential recoverable by CO_2-EOR

4.5.1 Key inputs and assumptions for the economic model

Out of the 81 fields considered previously a smaller number of promising candidates for CO_2-EOR are studied further, taking into account possibilities for CO_2 supply and under certain assumptions about the capital costs and range of carbon and oil trading prices. The purpose is to provide a first indication into whether large fields reaching the end of secondary production in the near future could turn into viable CO_2-EOR projects.

Fields selected

Figure 4.6 shows the production profile for the Forties field which is typical of most of the major fields in the UK sector such as Brent, Ninian, Piper, Miller, Scott, Fulmar, Claymore, South Brae, North Cormorant, Murchison, Thistle and Dunlin. It is also typical of prospects in the Norwegian sector such as Gullfaks, Ula and Gyda.

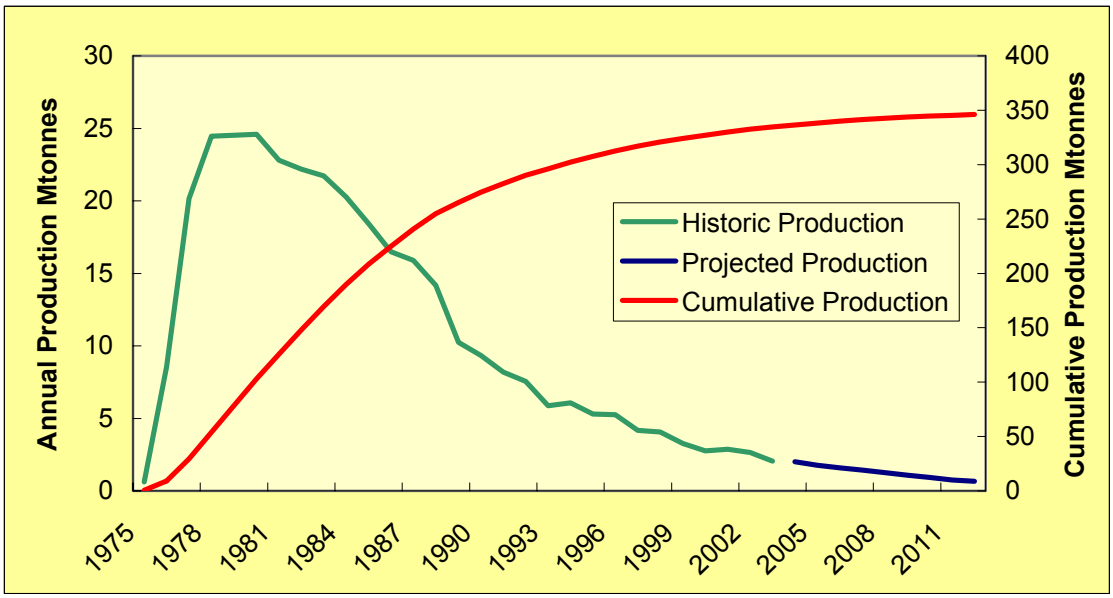

Figure 4.6 : Oil production history for the Forties Field in the UK sector

The well pattern required for a miscible displacement project could be similar to that deployed for water injection; hence the appropriate time for deployment would be any time during the tail end of secondary production. It is argued that after abandonment it would be difficult to re-enter a field to effectively implement an EOR project.

On the other hand, immiscible displacement projects are more likely to be deployed at the end of secondary recovery, around the planned end of production date, as the well pattern to be deployed is substantially different from that used in secondary recovery.

Fifteen fields [61], as shown in Figure 4.7, were selected for evaluation covering a range of sizes, CO_2-EOR techniques and geographic locations within the North Sea. The selected fields contain the larger urgent CO_2-EOR prospects that were identified in the review of fields. Their size in terms of OOIP is given in Table 4.9.

Table 4.9: Fields selected for evaluation of CO_2-EOR projects in the North Sea

Field	*Sector*	*OOIP*		*CO_2-EOR Type*
		M t	*M bbl*	
Auk	UK	106	795	Miscible
Brage	NO	133	998	Miscible
Brent	UK	499	3743	Immiscible
Claymore	UK	194	1455	Miscible
Dunlin	UK	110	825	Miscible
Forties	UK	560	4200	Miscible
Fulmar	UK	110	825	Miscible
Gullfaks	NO	507	3803	Miscible
N Cormorant	UK	143	1073	Miscible
Ninian	UK	302	2265	Miscible
Oseberg	NO	489	3668	Immiscible
Piper	UK	207	1553	Miscible
Statfjord	NO /UK	722	5415	Miscible
Tor	NO	120	900	Immiscible
Ula	NO	132	990	Miscible

Each of these fields was considered for an individual CO_2-EOR project in terms of identifying a CO_2 source large enough to meet the demand of the minimum CO_2 requirement for an EOR operation, calculating the cost of delivering the CO_2 to the sink by a dedicated pipeline and performing an economic appraisal of the project. The Brent and Oseberg fields are particular cases due to the very large amounts of CO_2 required and the fact that these cannot be provided by a single point source, so a collection of potential sources had to be identified.

For each field the option of continuing CO_2 injection and storage to the maximum potential was also reviewed. In this case the fields are used as CO_2 sinks and the change in profitability or the costs of this storage option were calculated.

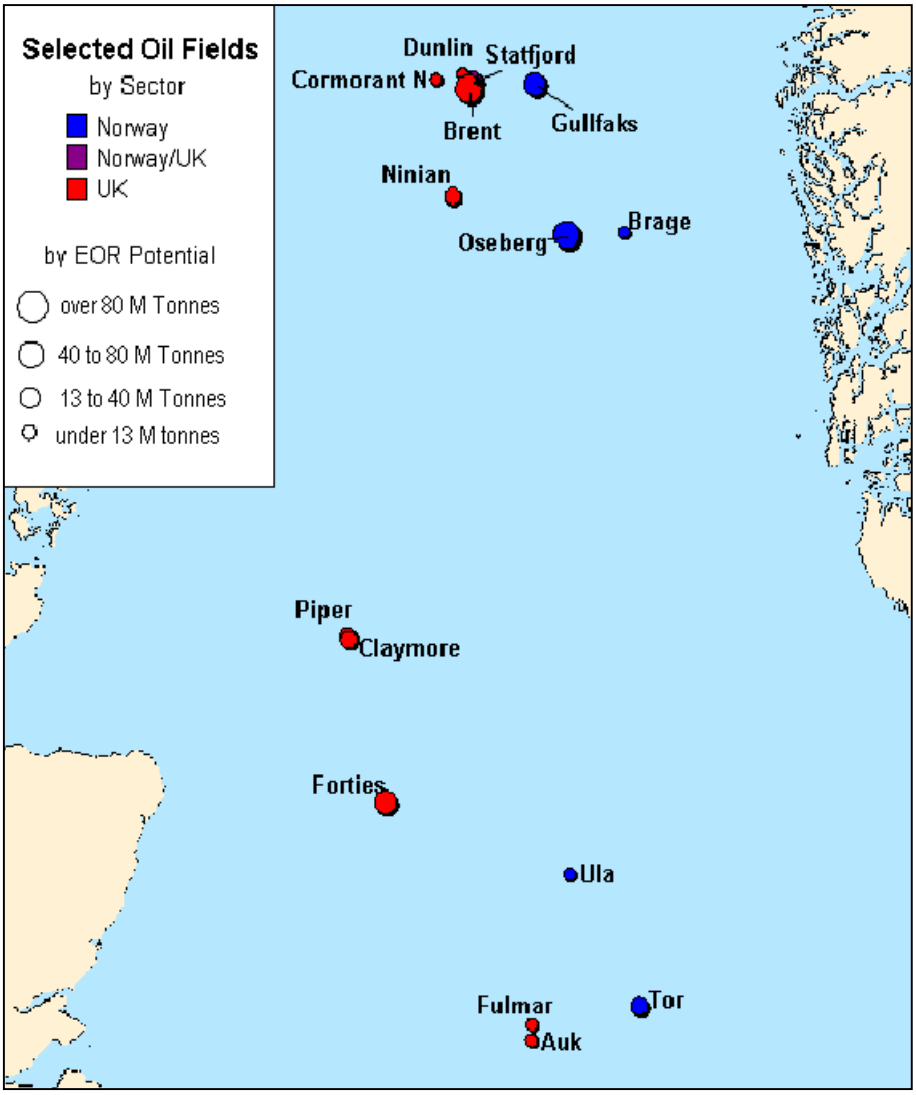

Figure 4.7: Fields selected for further assessment

Incremental oil

As discussed in section 4.3.1 for miscible projects an incremental oil rate of 3 barrels per tonne of CO_2 injected was used. The amount of CO_2 required was then determined from the amount of incremental oil produced, assessed for two different scenarios at 9% and 4% of the OOIP as shown in Table 4.1 and Table 4.2 respectively. As stated in section 4.3.2 the respective recovery factor for immiscible projects is set at 18% and 10% of the OOIP. For immiscible projects, the amount of CO_2 necessary was that required to re-pressurise the field and replace the original oil and gas reserves, as determined in Table 4.3 irrespective of the recovery factor assumed.

The estimate of incremental oil production is based on previous experience, which indicates yields of 7% to 15% of the OOIP using CO_2-EOR. However there are lower estimates given for the North Sea placing incremental oil production between 3% and 7% of the OOIP due to the different conditions and the increased secondary recovery yield of the offshore fields in this area [74].

Oil price

The oil price was considered constant throughout the project lifetime. Low and high oil price scenarios were defined at $25/barrel and $35/barrel respectively. These prices are considerably higher than the prices used by oil companies for the evaluation of prospective investments which are in the area $15-20/barrel [73, 74].

However they are lower than current oil prices at the date when the report was written, as shown in Figure 4.8.

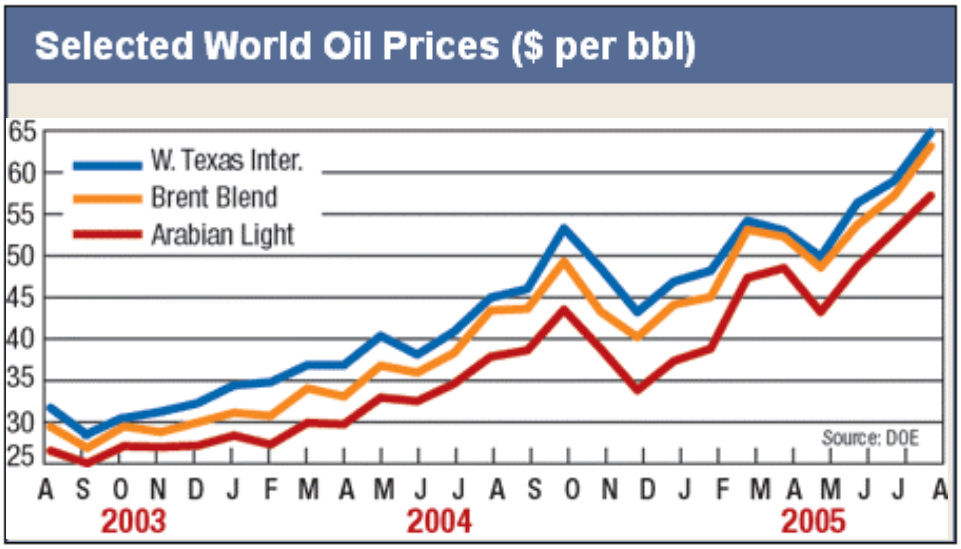

Figure 4.8: Selected world oil prices including North Sea Brent for the last 2 years. Source World Oil [75].

Project lifetime

The EOR projects considered were assumed to run for a 20-year period. On top of this period, 3 years for construction and 1 year of decommissioning were considered in the economic evaluation for all projects. Capital expenditure during the construction years is assumed to be 40% for the first year and 30% for the two remaining years. Incremental oil production starts 1 year after injection. The time frame for the implementation of the projects is more medium than short term due to the fact that much of the technology is still unproven on large scale and offshore and a CO_2 delivery infrastructure needs to be constructed before investments in this area can begin.

CO_2 sources and cost

The assumption for the purpose of this study is that the CO_2 for the EOR projects considered will be provided through post combustion capture from large coal- or gas-fired power generation stations. This technology was chosen as the most readily applicable in the short term in order to take advantage of the window of opportunity

presented for CO_2-EOR in the North Sea before a large number of promising fields have to be decommissioned. There are also other technologies for power generation with CO_2 capture– such as IGCC for example – that may prove to be a cheaper source of CO_2 when fully deployed. However, these options may have a longer time frame for realisation and are not examined in the present report. It is also acknowledged that power plants are not the only possible source of CO_2. Large industrial sources are also able to supply considerable amounts of CO_2 at streams that can also be more concentrated than those arising from power plants.

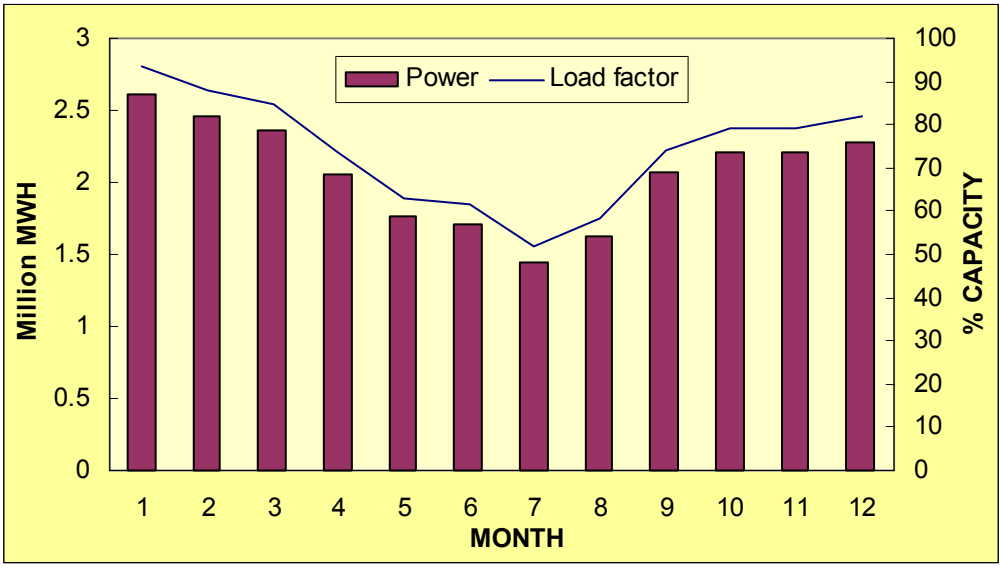

Figure 4.9: Monthly operation profile of a large coal fired power plant for 2004 [70]

Both the supply (at the plant) and demand (at the field) of CO_2 are considered uniform for all years during the lifetime of the project and the same applies for oil production, which is considered constant for each production year. CO_2 released by the oil production wells is separated and re-injected to the field. These assumptions are made to facilitate calculations at this preliminary evaluation. Other assessment studies [63],[66] have provided examples of oil production and CO_2 demand that vary with time through the lifetime of the project. The CO_2 demand changes during the years of the EOR operation, but in reality power plants are not under constant load and therefore CO_2 supply is not uniform either. Figure 4.9 shows an example of a monthly profile for the output of a large coal power plant, which varies by over 30%. In smaller plants larger load variations or cycling also occurs and may become more common in the future, in view of the increasing share of renewables in power generation. In a scenario where large investments are put in place for CO_2 capture, transport and utilisation all the involved parties would like to ensure that they can operate their facilities at optimum capacity, which may mean a constant/base load for power generation, almost full capacity for the pipeline and adequate CO_2 supply to ensure that the injection pattern in not disturbed during EOR operations. The co-ordination of all involved parties so that the above conditions are maintained is a

complex issue that requires detailed planning to ensure the smooth operation of the source-sink combination(s).

The present assessment is based on power plants in operation at the time of the study and draws on their geographical location and emission characteristics to provide input for the calculations performed. The examples are indicative and by no means exhaustive. Our restriction to plants in operation means that planned complexes are not included and future possible sources that may be more advantageous to the projects are not considered. This may be especially apparent in the case of Norway, where there are presently no major fossil fuel powered stations, but there are plans for the construction of a number of natural gas-fired units of considerable size for the near future.

Plant location and characteristics are taken from the PowerVision database [70], while annual CO_2 emission data are adopted as calculated by the European Pollutant Emission Register (EPER) [71] for 2001. These figures are selected as indicative values in order to perform a preliminary assessment. Detailed studies involving specific new plants would have to be performed to assess the feasibility of individual projects.

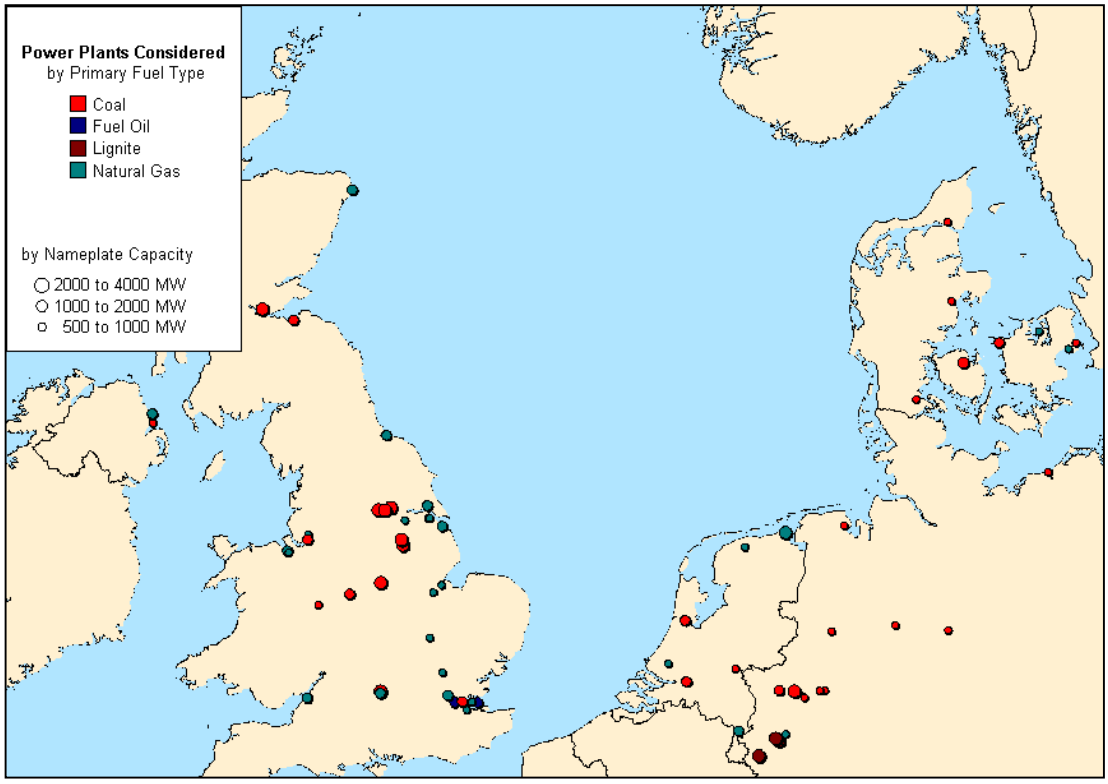

Figure 4.10: Power plants considered as indicative CO_2 sources for the study

To minimise the costs involved in the CO_2 capture and transport process, large power plants (over 500 MW nameplate capacity) in the area of northern Europe are targeted. Figure 4.10 shows the power plants considered by the study.

However, it is not proposed that these facilities will be retrofitted to capture CO_2 as this is recognised to be a difficult option both technically and financially. The assumption is that upon retirement of old stations, or need for new capacity, the same locations could be used due to existing licences, land ownership and infrastructure and that the new plants could be designed to operate with CO_2 capture. Both locations and operational data for the power plants are indicative and serve only as an example as the same evaluation could be performed for a number of other CO_2 sources.

Consistent with the above assumption the costs of CO_2 capture and of the associated electricity generation are calculated according to previous JRC studies on the subject [2, 4], with the most important figures summarised in Table 4.10. The cost of electricity displayed here is also the electricity cost used in the economic evaluation of the project, under the assumption that the power plant, CO_2 pipeline and EOR operation are part of an integrated project which allows for the advantage of electricity supply at production costs. The CO_2 capture cost is the cost of supplying dry, clean, CO_2 pressurised at 110 bar at plant gate prior to pipeline transport to the oilfield. This cost is an estimate referring in advance to a fully deployed technology, which is not yet in place at this scale, and therefore there is a certain degree of uncertainty involved. It may be that by the time CO_2-EOR projects are under way, costs are actually lower due to the learning curve and future development of the technology. The figures given for avoided emissions include the drop in the efficiency of the plant due to the energy consumed by the capture and compression of CO_2 before it is delivered to the pipeline for transport. Additional data for the power plants assumed can be found in Appendix II.

Table 4.10: Estimated CO_2 and electricity prices for power plants with CO_2 capture.

Plant	*Fuel cost*	*CO_2 cost*	*Electricity price*	*CO_2 emittance*	*CO_2 avoided*
	€/GJ	**€/tonne**	**€c/kWh**	**kg/MWh**	
Coal (supercritical)	2	25.2	7.00	103.3	72%
Natural gas (combined cycle)	5.5	38.55	6.13	42.4	86%

A preliminary assessment was performed considering a source – sink relationship for a number of plants in the proximity of each oil field to assess the impact of the type of plant and its location to the economics of the project. Figure 4.11 shows the change in the profitability of a CO_2-EOR project for a given field versus the type and distance of the CO_2 source. The trend in this first screening is the same for all fields and shows that the aim should be to keep the requirement for CO_2 pipeline length to a minimum

by locating a single source that can cover the field's CO_2 requirements at the shortest possible distance. It is also clear that, for the technology assumed for power generation and CO_2 capture, coal power plants have a big advantage over their natural gas counterparts as CO_2 sources for EOR operations. The difference in the capture cost of CO_2 allows this advantage to be maintained in most cases even if the location of the natural gas plant is closer to the oil field by well over 200 km. The above shows that EOR projects can act as a CO_2 sink for a limited number of sources located in the vicinity of the fields. Moving the supply from UK sources (~400km) to a source in Germany (~800km) reduces the project return rate by more than 5%.

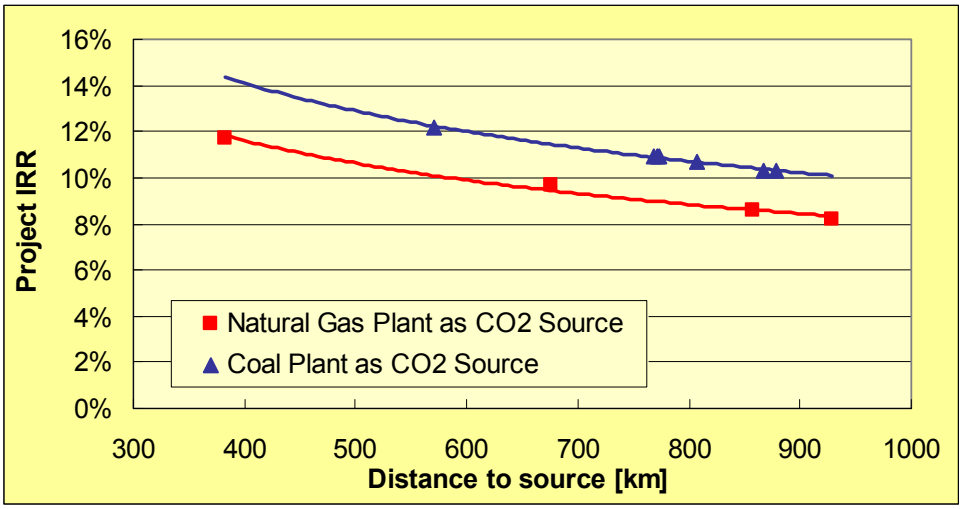

Figure 4.11: Preliminary screening of the effect of distance and CO_2 source on the potential profitability of a CO_2-EOR project. (IRR: Internal Return Rate).

Figure 4.12 shows the power plants selected as best potential sources for the urgent EOR projects identified, based on their CO_2 emission levels and distance from the sink. For the reasons described above all plants selected for one-to-one projects are coal power plants. In the cases where more than one source is needed to fulfil the CO_2 demand of a field natural gas plants near the selection points are also utilised as sources. These plants are selected based on a scenario of supplying enough CO_2 to cover the minimum required demand for the EOR projects i.e. for projects that are designed to minimise CO_2 use.

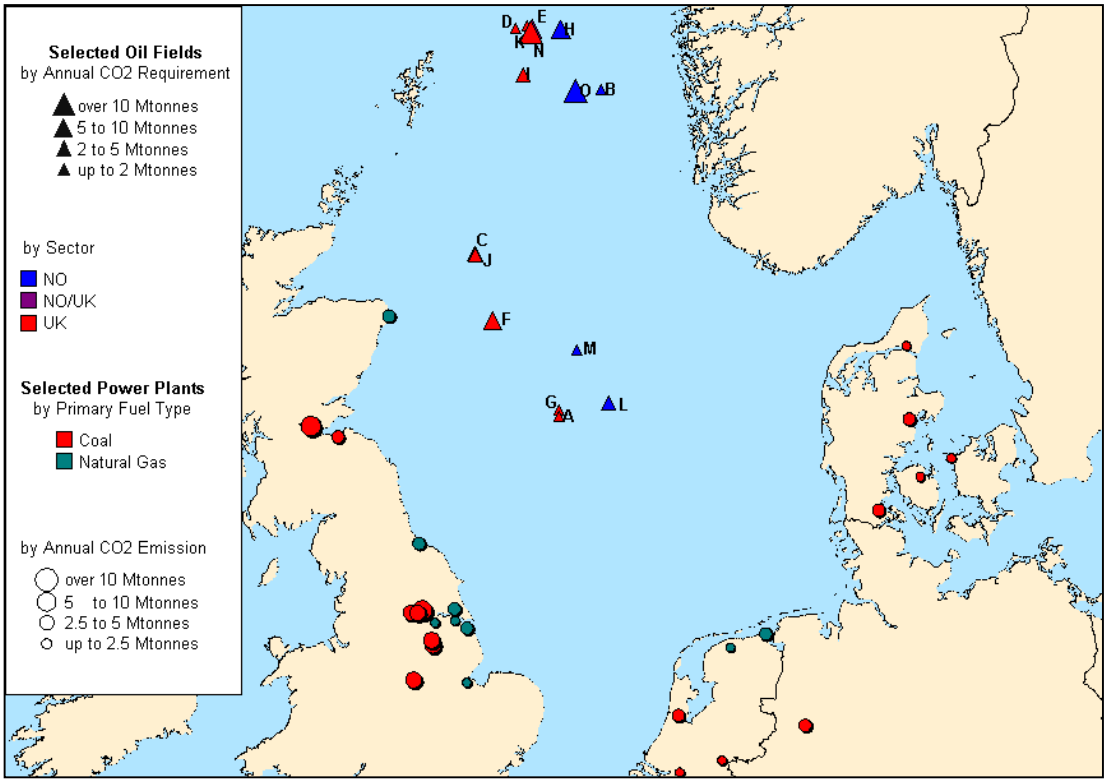

Figure 4.12: Selected oil fields and CO_2 sources

CO_2 transport infrastructure

The CO_2 is supplied dry at a temperature over 32°C and pressurized to 110 bar (supercritical fluid) at the entry of the pipeline. To avoid the formation of carbonic acid, the relative humidity of the CO_2 must be under 10 ppm.

The pipeline specifics and capital costs were calculated according to the IEA Greenhouse gas R&D programme report on "Transmission of CO_2 and Energy" [72]. This model is only intended for preliminary assessments; actual transmission project studies will require more detail for all aspects of the pipeline construction and operation. Conditions at the pipeline outlet for CO_2 pressure and velocity were set to over 84 bar and under 20m/s respectively. The pipeline route from the sources to the oilfields was designed to follow the outlay of natural gas pipelines where possible, assuming that the routes already mapped out are likely to be followed for new construction to avoid further risk and cost. Figure 4.13 displays the effect of this assumption on the calculated distances for the pipeline infrastructure. The required pipeline length assumed in this instance is 70% more that the straight-line distance between the CO_2 source (Cockenzie power plant) and the oil field (Auk). However, a dedicated gas pipeline to the field follows the same outlay implying that underlying technical reasons dictated the route. A summary of the input assumptions for the pipeline calculation can be found in Appendix V.

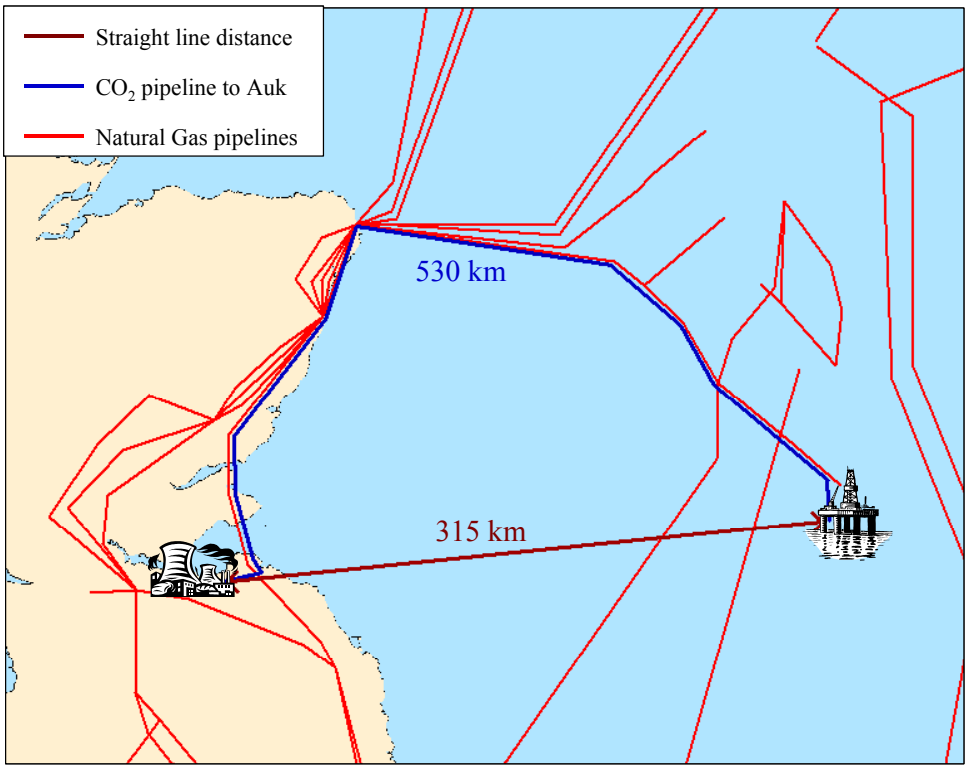

Figure 4.13: Example of CO2 pipeline route following the gas pipelines already in place in contrast with a straight-line distance.

For the projects requiring multiple CO_2 sources, the calculation of the pipeline diameter was done considering a weighted average flow mass depending on the length of each branch and ensuring that, for the calculated average diameter and for the average mass flow, the outlet pressure at the end of the longest branch is over 84 bar. In total three different sets of pipelines were calculated to cover the scenarios investigated in this study:

- Dedicated pipelines from the nearest adequate source or a collection of sources to the sink, designed to transport the minimum amount of CO_2 required for a successful EOR operation (Table 4.11). In the case of miscible projects the size is based on the CO_2 required for the recovery of 9% of the OOIP.
- Dedicated pipelines from the nearest adequate source or a collection of sources to the sink, designed to transport an increased amount of CO_2 necessary for the oilfield to reach its maximum CO_2 storage potential at the end of the 20-year injection process (Table 4.12).
- An integrated pipeline network aimed at simultaneously providing all selected fields with the minimum amount of CO_2 required for successful EOR operations (Figure 4.14).

For the integrated network project each onshore pipeline group (North U.K., South U.K., Netherlands and Denmark) and the offshore pipeline grid were calculated separately.

Table 4.11: Pipeline length, cost and annual CO_2 throughput to the fields. Values based on the minimum amount of CO_2 required.

Project	*Field*	*Pipeline Length*	*Pipeline Cost*	*Annual CO_2 requirement*
		km	**M €**	**Mt**
A	Auk	530	208	1.2
B	Brage	665	295	1.5
C	Claymore	409	176	2.2
D	N Cormorant	677	320	1.6
E	Dunlin	691	249	1.3
F	Forties	368	230	6.3
G	Fulmar	540	215	1.3
H	Gullfaks	705	540	5.7
I	Ninian	630	350	2.4
J	Piper	411	178	3.4
K	Statfjord	699	641	8.1
L	Tor	555	334	3.5
M	Ula	554	230	1.5
N	Brent[30]	939	1313	39.5
O	Oseberg[30]	892	1558	29.1

Table 4.11 shows the fifteen projects with the pipeline length assumed from the oil field to the identified CO_2 source, the estimated pipeline cost and the annual CO_2 throughput from the source to the sink. In this case all projects are considered separately and therefore a number of them use the same CO_2 sources, selected as optimum for the project as mentioned in the section describing CO_2 sources and cost. This data refers to the transport of the minimum amount of CO_2 required for a successful EOR operation.

[30] The Brent and Oseberg oil fields are connected to multiple sources due to the large amounts of CO_2 required

Table 4.12: Pipeline length, cost and annual CO_2 throughput to the fields. Values based on the injection of a maximum amount of CO_2 during oil production.

Project	*Field*	*Pipeline Length*	*Pipeline Cost*	*Annual CO_2 requirement*
		km	**M €**	**Mt**
B	Brage	663	313	2
C	Claymore	430	224	4.1
D	N Cormorant	701	369	2.9
E	Dunlin	691	348	2.6
F	Forties	450	290	13.7
G	Fulmar	559	301	4.4
H	Gullfaks	1079	974	21
I	Ninian	630	510	8.6
J	Piper	435	297	7.5
K	Statfjord	1104	1706	42.4
M	Ula	559	305	4.2

To facilitate the presentation of results each project is assigned a letter describing a specific source-sink combination and scenario as shown in Table 4.11. The same letters per field are used underlined in Table 4.12 to denote this sink combined, if needed, with a different source in the scenario that looks into reaching maximum CO_2 storage at the end of the EOR project.

The integrated network scenario as presented in Figure 4.14 is estimated to have a total length of 5166 km and a cost just under €7 billion.

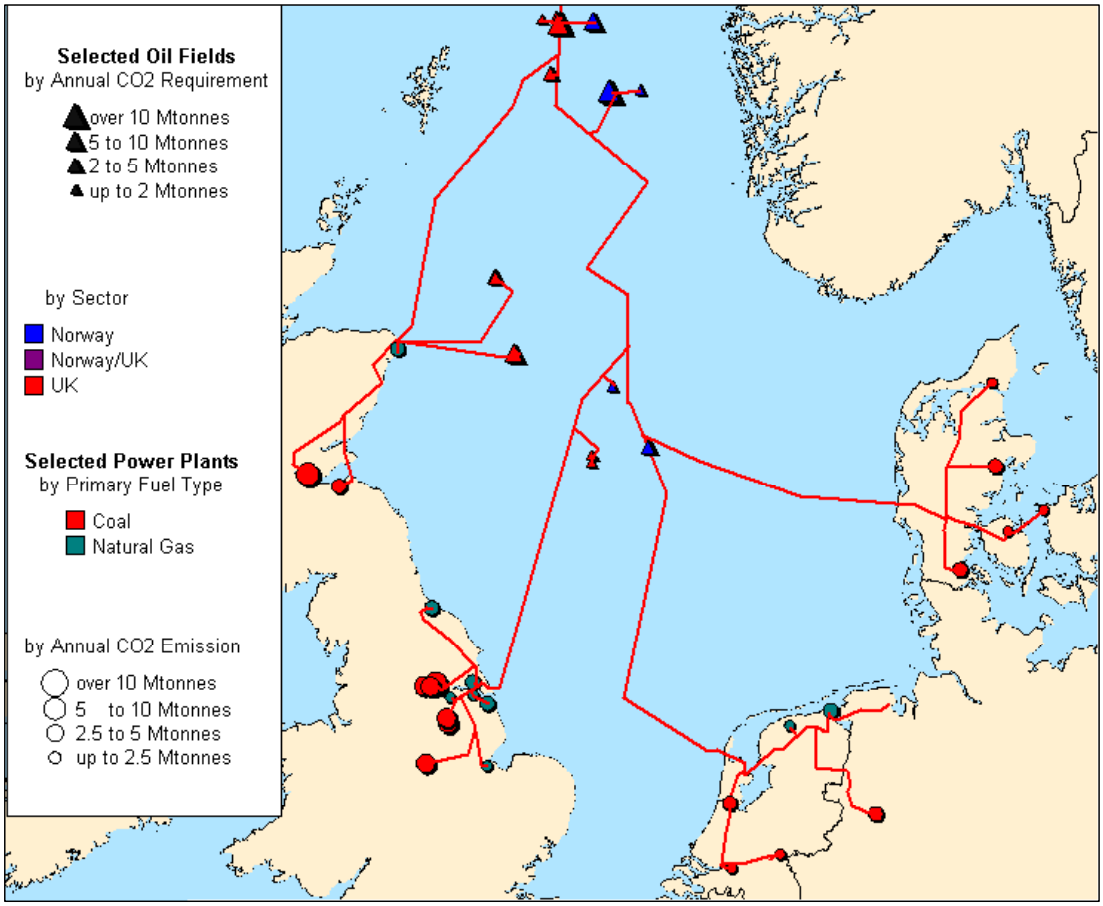

Figure 4.14: Integrated network of selected fields for CO_2-EOR in the North Sea

CO_2 injection and gas processing infrastructure

Some wells in the North Sea are already designed to manage the effects of CO_2 corrosion, as some of the oilfields naturally contain significant quantities of CO_2. There is uncertainty in the capital costs associated with specific field deployment, hence detailed design studies would be necessary to give confidence in the cost of modifying wells and topside structures to the optimum detailed implementation for specific fields.

For the purpose of this evaluation an equal number of new and reused injection wells were assumed. Costs for a substantial number of new wells were provided for, based on an assessment of the existing level of field infrastructure deployed during secondary recovery. The drilling depth was determined from reservoir information contained in the review of fields. Drilling costs of €1.75 million /km were used for new wells, with a capital cost of €0.5 million assessed for reconfiguration of existing injection wells.

A capital cost for topside modifications, such as provision of separation facilities for produced water, oil and CO_2, of €2/incremental barrel was used.

A total of €7.5 /barrel was provided for oil field operation and maintenance costs.

A decommissioning cost of €450 million for large platforms and €250 million for small platforms is assumed as an expense at the end of life [61]. If EOR is not to be undertaken these costs will be incurred much earlier.

A large potential commercial benefit for undertaking EOR is the deferral of the significant expense of decommissioning, particularly for the large steel platforms. A factor that will be taken into account in determining the decommissioning date is the status of the satellite fields that have also been developed. These satellite fields tend to be smaller than the main field, and also deplete more quickly. As the province becomes more mature, there becomes less scope for development of additional satellite fields to sustain a viable level of oil production from the platform, and hence deployment of EOR may become a more significant option for achieving substantial deferral to the decommissioning date.

CO_2 trading

Low and high price scenarios for the value of CO_2 captured and remaining stored in the oil reservoir after injection are set to €15/tonne and €25/tonne respectively. These prices are considered realistic for the medium term, and may even be considered conservative based on recent CO_2 trading prices as shown in Figure 4.15.

It is estimated that 82% of the CO_2 injected is actually stored underground, both for miscible and immiscible projects [61], and therefore credits are received for this quantity. It is also assumed that the mechanism for receiving benefits for such operations is in place and no consideration is given here to legislative issues or different carbon tax schemes that may be in place. For the economic evaluation the benefits from carbon trading are perceived as income.

Figure 4.15: EU allowance (EUA) historic trading prices per tonne of CO_2 up to July 2005. Source: Point Carbon [76]

Estimation of the CO_2 avoided

The process of capturing, transporting and injecting CO_2 for EOR requires energy input and results in CO_2 emissions. Since these are all caused by the CO_2 storage process, they have to be taken into account in order to calculate the amount actually avoided from emission to the atmosphere.

The last column of Table 4.10 represents an estimate of the CO_2 avoided as a percentage of the amount captured for the process of electricity generation by each type of plant when coupled with carbon capture. Due to reduced power plant efficiency, compared to the option without CO_2 capture, the CO_2 avoided is 72% and 86% of the volume available for storage (at the pipeline entrance) for coal and natural gas power plants respectively. The CO_2 emittance of the plant given in the same table is used to calculate the CO_2 emission attributed to the electricity consumption necessary for the pipeline transport.

CO_2 emissions for the injection and recycling of the gas during the EOR operation can be estimated by adopting an emission factor. The value of 0.048 tonnes of CO_2 per incremental barrel of oil produced is derived from literature [77] to account for fugitive emissions, flaring and auxiliary processes. This is an emission factor specific to extra processes related to EOR and does not refer to generic oil production. While there are emissions from the general operation of the oil field these are not taken into account in this balance. The reasoning behind this is that the incremental oil produced because of the EOR operation will be replacing oil extracted by some other method. Therefore these are emissions that would have occurred anyway through oil production. For the sake of simplicity it is assumed that the incremental oil production replaces oil produced in the North Sea, with comparable CO_2 emissions during the extraction process.

According to the above it is calculated that in the case of miscible projects about 58% of the CO_2 delivered at the sink (minimum CO_2 requirement) can be considered as CO_2 avoided from emission to the atmosphere. For immiscible projects the figure varies from 57% to 61%. The costs and cash flows produced by the economic evaluation are normalised to this calculated amount of CO_2 avoided.

This is a very simple balancing of the CO_2 flows involved in the systems studied. It does not include all the associated processes or particular aspects of each project and assumes no further interactions beyond the system boundaries. To gain a better insight of the CO_2 balance, more detailed studies of the individual project systems should be performed in terms of life cycle assessment of the energy use and emissions throughout their operation, taking into consideration the specific characteristics of each project.

A life cycle assessment study of a proposal for CO_2 separation and injection in the Gullfaks field [78] finds a reduction of 53-59% in GHG emissions compared to the previous operation of the power plant and field involved. However, this reduction has to be weighted against other impact categories, which show an increase with the introduction of the project. Energy consumption, especially during the separation of CO_2 is the dominant cause of environmental stress and therefore the performance of different projects is sensitive to the energy sources used and the accuracy of the data describing them for the LCA studies.

Financing, Discount rate, Inflation and Tax rate

Financing of the projects is assumed to be 100% equity. No scenarios were run for debt financing in the present study to avoid complications. There is a wide variety of financing options for commercial projects, however the choice and evaluation of these is outside the scope of the study.

All evaluations are performed taking into account the initial investment and pre-tax cash flows (Earnings Before Interest, Taxes, Depreciation, and Amortization).

The net present value of the projects is calculated for a discount rate of 10%. Rates used in similar studies range from 7% to 11% [74].

The impact of inflation on the economics of the different projects is not considered.

The results presented here should not be taken to indicate conditions under which the projects would be feasible. Rather this is a general study to present an overview of the situation under simplified assumptions. Information derived from this effort, combined with an insight into the specific financial conditions present, may give an indication of projects that are worth further detailed investigation or that should be disregarded.

In advanced project-specific feasibility studies inflation will not be ignored and the taxation/royalty system in place will be taken into account along with the specific scheme for the financing of the project. These conditions, along with the real expectation for the return on capital may vary significantly across the parties involved and the discussion about the different policies in place and assumptions about their future development lie outside the scope of this study. It is evident though that these issues can have a considerable impact on the commercial viability of a project.

Other considerations

For a number of oil fields natural gas is a profitable by-product of the oil extraction process. However, if CO_2-EOR is applied it is possible that large amounts of CO_2 will be mixed with the natural gas produced which will make it impossible to export without further treatment. Cleaning up the natural gas will require extra infrastructure and energy and may not be a viable option. The alternative is re-injecting the natural gas along with the breakthrough CO_2 back into the well, which will mean that income from potential gas sales will be lost. Calculations performed here only refer to oil production and have not taken this issue into account, but it may be of significance especially for fields with a large gas cap, where the potential for CO_2 storage may also be affected by natural gas re-injection.

4.5.2 Results

CO_2 transport costs

The projects considered are defined to include both transport and injection infrastructure costs. However, in order to get an idea of the cost breakdown the marginal cost for CO_2 transport has been estimated by considering the pipeline operation as a stand-alone project. The transport costs are based on an annual discount

rate of 10% and a project life of 20 years, and refer to the price that would return a net present value of zero given the capital expenditure and operating costs of the pipeline.

The normalised costs for CO_2 transport in the different projects, calculated according to the assumptions mentioned above for pipelines following the specifications set out in the paragraph describing the CO_2 transport infrastructure, range from €6 to €30 per tonne of CO_2, or between 1 and 3 €c per tonne·km of CO_2 transported. As expected, due to the economy of scale, projects requiring smaller amounts of CO_2 incur greater transport costs, especially when longer transport distances are involved. For the integrated network project the cost of CO_2 transport is 1.6 €c per tonne·km.

The costs calculated here are comparable to the range of costs reported by other studies, a selection of which is given below for comparison. The costs given in parenthesis have been normalised per tonne·km of CO_2 transported and converted to €c using the assumed rate of $1.25 to €1.

- Gale and Davison [79] report a cost of $6/tonne for an onshore and $15/tonne for an offshore pipeline for the transport of 1.5 million tonnes CO_2 per year and a 300km pipeline (1 €c/tonne·km and 3.3 €c/tonne·km respectively). If the quantity of CO_2 is increased to 3.3 million tonnes per year the cost decreases to $9/tonne for an onshore and $22.5/tonne for an offshore pipeline (0.7 €c/tonne·km and 1.8 €c/tonne·km respectively).
- Anderson and Newell [80] give a transport cost of $1.5-2.9 per tonne and 100 km (1.2-2.4 €c/tonne·km)
- CICERO [81] in a working paper quote transport and compression cost of $7.7 per tonne and 100 km for transport of 1Mtonne/annum CO_2, and $3.3 per tonne and 100 km for transport of 4Mtonne/annum (6.2 €c/tonne·km and 2.6€c/tonne·km respectively).

Due to the benefits of the economy of scale and the flexibility inherent in pipeline networks a number of studies [46, 79] find that it might be advantageous to build pipelines with the future in mind, providing for excess capacity and interconnection between sources and sinks. These could be cheaper and more profitable to run in the long term. Larger pipeline projects, which have spare capacity and rely on more than one source and sink would also be better equipped to deal with intermittent operation of one of their suppliers or customers.

Minimum required CO_2 volume from the nearest single source – High Incremental oil recovery

Figure 4.16 and Figure 4.17 show the cumulative effect of the implementation of the selected individual projects if the incremental oil recovery factors of 9% and 18% of the OOIP are assumed for miscible and immiscible projects respectively. Starting from the most profitable option, and setting a limiting rate of return that would decide project viability, also indicates the amount of CO_2 that can be avoided and the incremental oil that may be produced from projects within that range. These calculations assume that production of incremental oil begins one year after CO_2 injection commences.

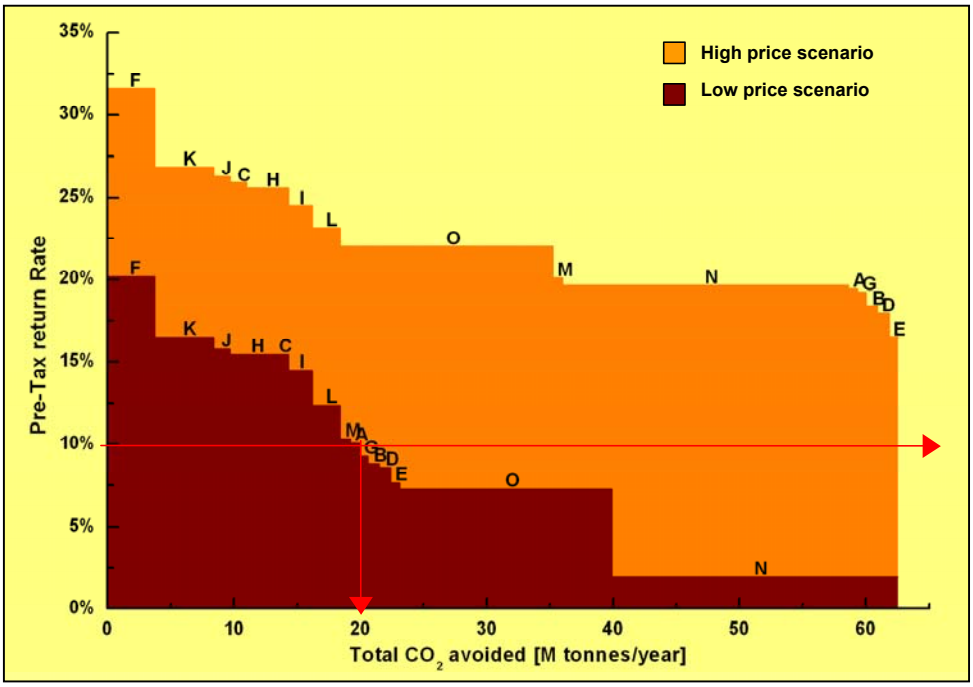

Figure 4.16: Potential cumulative CO_2 avoided depending on the project return rate acceptable for realisation. 1-year lag between CO_2 injection and oil production for all projects . Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

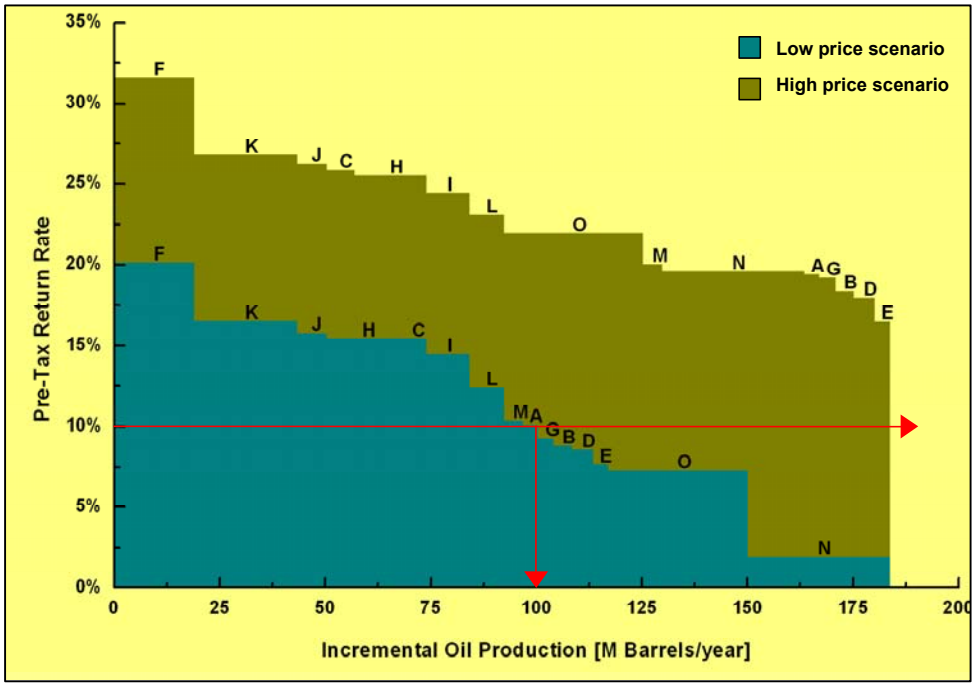

Figure 4.17: Potential cumulative incremental oil produced depending on the project return rate acceptable for realisation. 1-year lag between CO_2 injection and oil production for all projects. Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

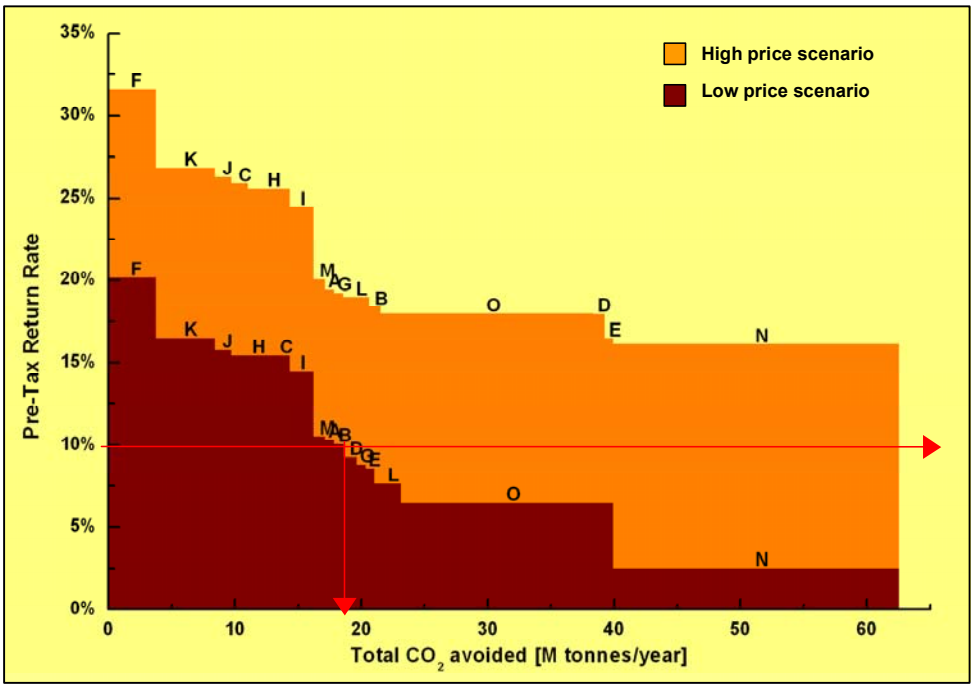

Figure 4.18: Potential cumulative CO_2 avoided depending on the project return rate acceptable for realisation. 8-year lag between CO_2 injection and oil production for immiscible displacement projects (L, O, N). Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

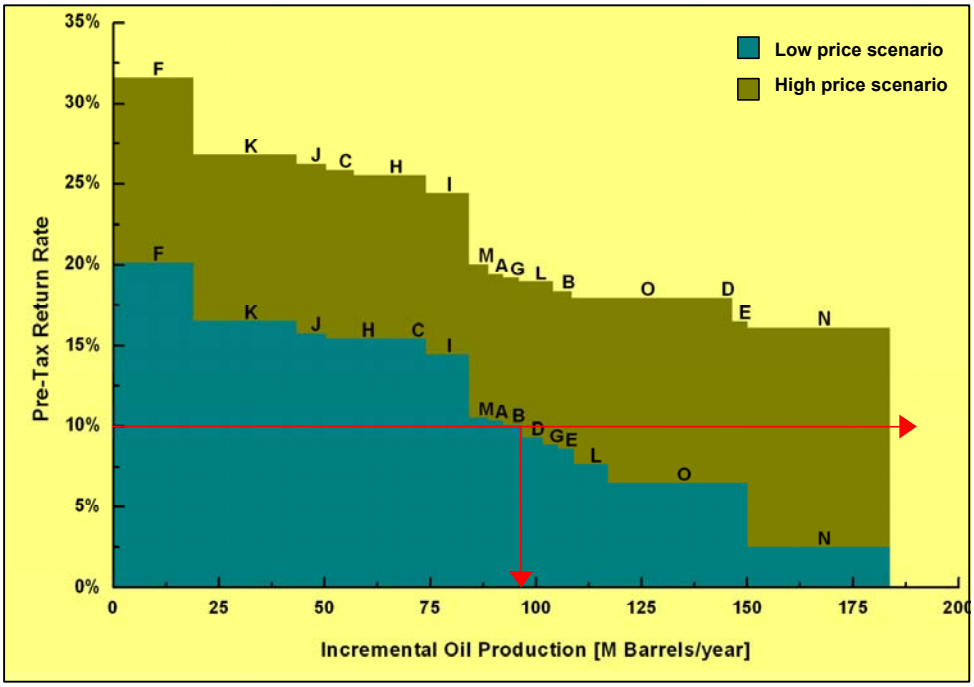

Figure 4.19: Potential cumulative incremental oil depending on the project return rate acceptable for realisation. 8-year lag between CO_2 injection and oil production for immiscible displacement projects (L, O, N). Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

For example, if the desirable pre-tax return rate is set at 10% then under the low price scenario about half of the projects would be viable leading to an incremental oil production of approximately 100 million barrels per year and approximately 20 million tonnes of CO_2 avoided per year. This represents 58% of the oil potential and 32% of the CO_2 that could be avoided if all projects were profitable. However, if a longer period is assumed between the start of CO_2 injection and incremental oil production for the immiscible projects the number of viable projects is reduced. Figure 4.18 and Figure 4.19 display the potential when the time lag between injection and incremental oil production is set to 8 years. In this case oil production and CO_2 storage potential are reduced by 10.5% and 8% respectively. Figure 4.20 shows the distribution of this potential between the UK and Norwegian sectors, assuming an 8-year lag for immiscible projects. Out of the total potential for incremental oil production from projects recognised as urgent, which would be sound given the 10% return rate, 24% is located in the Norwegian sector, while another 29% is in projects in the UK sector. The remaining 47% of the potential cannot be realised. In terms of CO_2 avoided the same projects in the Norwegian sector will fulfil 14% of the total potential, while profitable projects in the UK sector account for another 16%. However, under the high price scenario all projects are profitable and the yield reaches approximately 184 million barrels of incremental oil and 62 million tonnes of CO_2 avoided annually. Results are presented in detail in Appendix IV.

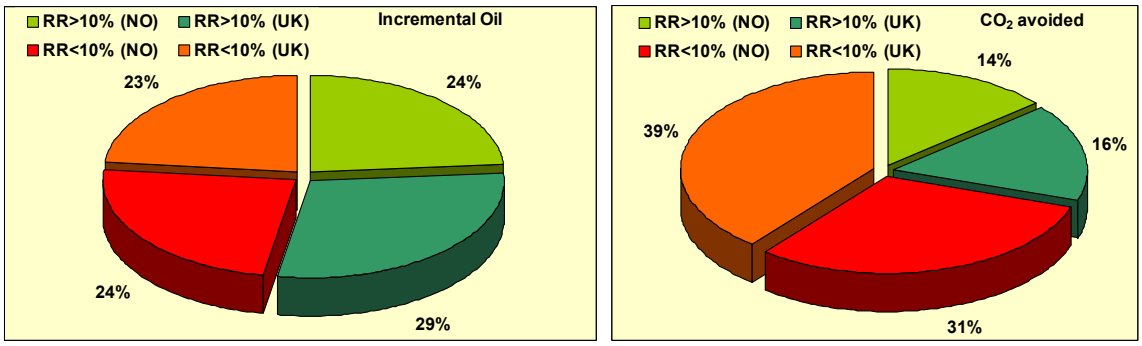

Figure 4.20: Distribution of total potential for incremental oil recovery and CO_2 avoided according to sector and project profitability. Plotted for the low price scenario and a discount rate of 10%. 8-year lag between CO_2 injection and oil production for immiscible displacement projects. Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

The representation in the graphs is theoretical. The projects in their present format cannot all be realised simultaneously under current assumptions since they use the same (optimum) CO_2 sources, which would therefore not be able to meet all the demand. However, since the source location and capacity is indicative and would be reviewed in feasibility studies this represents a possible scenario should the picture of electricity generation with CO_2 capture in the future develop so as to fit the assumptions made. In order for this to happen the power output from coal fired generation stations in the areas considered would have to increase by approximately 3.5 times.

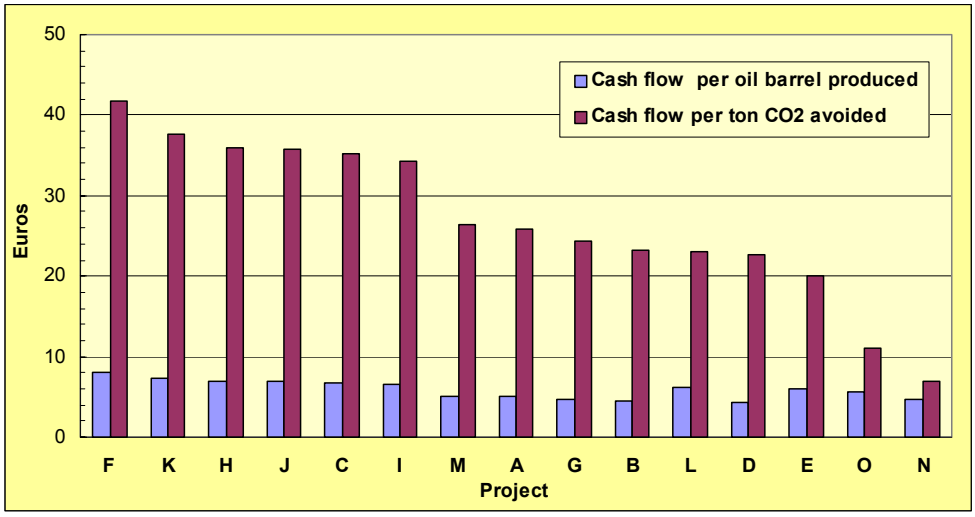

Figure 4.21: Average cash flow per incremental barrel of oil produced and tonne of CO_2 avoided over the project lifetime for the high price scenario. Discount rate assumed at 10%. 1-year lag between CO_2 injection and oil production for all projects. Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

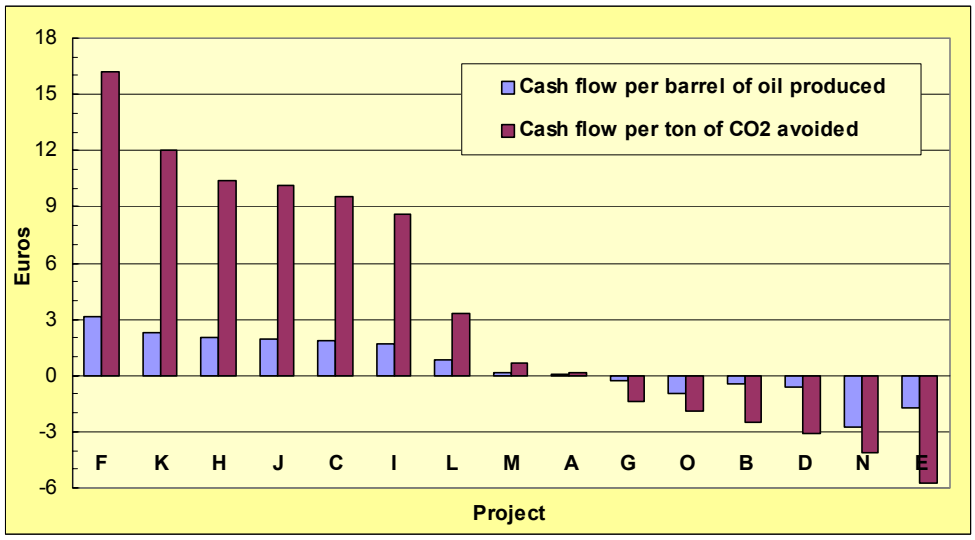

Figure 4.22: Average cash flow per incremental barrel of oil produced and tonne of CO_2 avoided over the project lifetime for the low price scenario. Discount rate assumed at 10%. 1-year lag between CO_2 injection and oil production for all projects. Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

If only viable projects under the low price scenario were to be considered (as marked in Figure 4.16 and Figure 4.18) then coal fired power generation in the North of the UK would have to increase by a factor of 2.5 in order for the CO_2 supply to be adequate. This does not necessarily mean installing new capacity, as the emission quantities for some of the plants considered in the study refer to annual average load

factors of around 50%. A load increase or shift, meaning the plants would operate at load factors closer to installed capacity, would almost double emissions from these sources without any new capacity being installed.

Figure 4.21 and Figure 4.22 show the financial gain or loss for each project normalised against the estimated incremental oil produced and amount of CO_2 avoided for the two price scenarios. Smaller fields in terms of oil production and CO_2 storage potential and projects requiring large initial investments are more likely to suffer when pricing is less favourable and are therefore the ones which can withstand less risk. These are also the projects characterised by lower return rates in the previous graphs (Figure 4.16 to Figure 4.19). When these fields are used as sinks for CO_2 storage Figure 4.22 shows that there is an average loss of €6 per tonne of CO_2 avoided for the least favourable project examined. For reference the capital expenditure for each project is plotted in Figure 4.23.

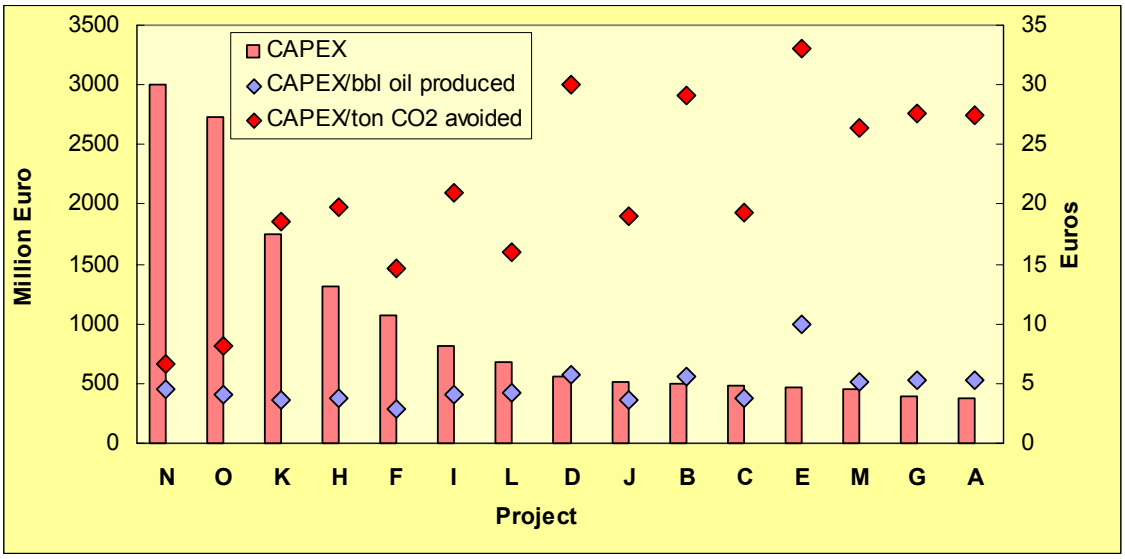

Figure 4.23: Capital expenditure for each project as an absolute sum and normalised against the incremental oil production expected and estimated CO_2 avoided throughout the project lifetime. Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

Figure 4.24 shows the relationship between CO_2 credit prices and oil prices so that each project will be marginally viable – returning a net present value of zero. As marked on the plot the area under each line representing a project is a price combination area not favourable for investment, while the opposite is true if the predicted prices indicate a point over the project line. With current oil prices almost all projects could be considered for further evaluation and for a number of fields a CO_2-EOR project could be viable even without a carbon-trading scheme. However, as discussed in section 4.5 the assumptions of this study differ considerably from those used by stakeholders during project evaluations. In essence the oil price depicted here

represents the cost of production per barrel and the effect that a CO_2 storage credit will have on this figure for the different projects. If one excludes projects O and N, which are special cases of immiscible EOR requiring large amounts of CO_2 and high capital investments, the effect of carbon trading credits is similar for the remaining cases. If a CO_2 credit of €15 per tonne is assumed according to the low price scenario then an average drop of 14% ($3.7/bbl) in the oil price is observed, compared to having no credits from CO_2 storage, with prices being under $30/bbl for all projects. In the case of the high price scenario and a CO_2 credit of €25 per tonne the reduction would be in the area of 23% ($6/bbl), compared to having no credits from CO_2 storage, and the oil price for almost all projects could fall under $25/bbl.

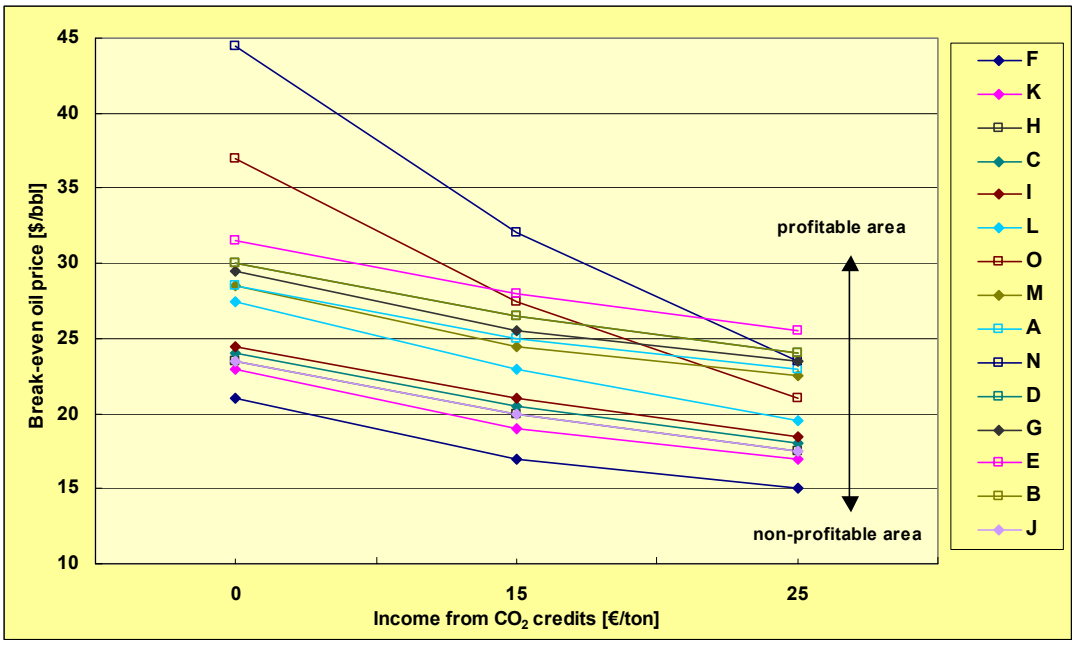

Figure 4.24: Break-even oil prices for the projects against CO_2 storage credits. Discount rate at 10%. 1-year lag between CO_2 injection and oil production. Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

Finally, in the case of immiscible CO_2-EOR projects, given that there may be a significant time delay between the beginning of the injection process and the response in oil production, the project return rates have been recalculated to reflect the effect of this time lapse. Figure 4.25 shows the influence of increased time delay in the production of incremental oil on the profitability of the three immiscible projects included in this assessment both for the high and low price scenarios. Operation costs for the field are reduced accordingly for the years with no incremental oil production, while all other assumptions are maintained. It is apparent that the long response times are detrimental to project economics, and the effect is more prominent for the high price scenario.

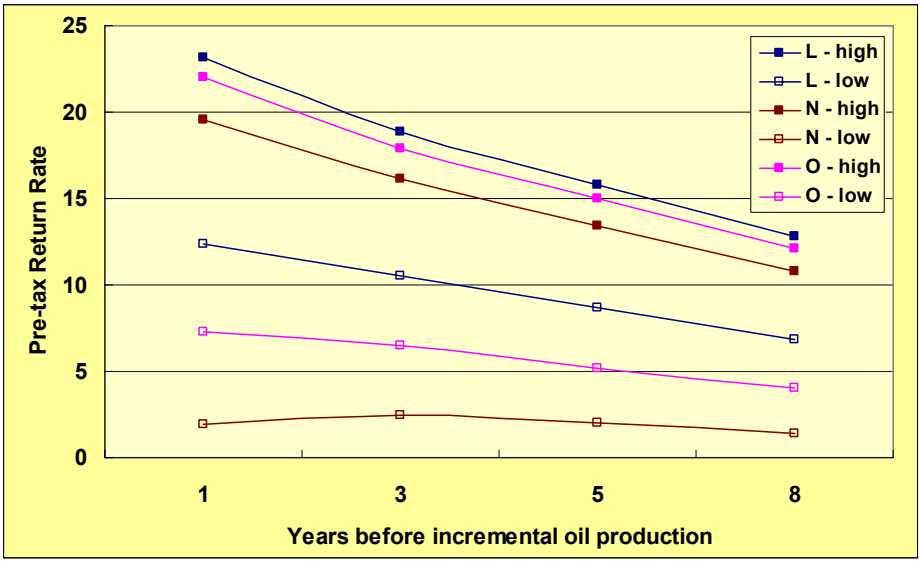

Figure 4.25: Influence of time delay between the start of injection and incremental oil production on the project profitability for immiscible CO_2-EOR projects. Oil recovery at 9% and 18% of OOIP for miscible and immiscible projects respectively.

Minimum required CO_2 volume from the nearest single source – Low incremental oil recovery

In the case of low incremental oil recovery (4% for miscible and 10% for immiscible projects) the potential for incremental oil recovery from the selected fields is reduced by 50% compared to the results presented in the previous section. Due to the fact that the majority of the CO_2 is injected in immiscible projects, and therefore independent of the oil recovery rate, the potential for CO_2 avoided is only reduced by 7%. Taking also the project economics into account (for a 1-year lag between CO_2 injection and oil production) the results for potential cumulative CO_2 avoided and oil recovery are as shown in Figure 4.26 and Figure 4.27.

Assuming again that a 10% discount rate represents a viability threshold, under the low price scenario approximately 20 million barrels of incremental oil could be produced yearly with just under 4 million tonnes of CO_2 avoided per year. This represents 21% of the incremental oil potential and 7% of the CO_2 potential for the selected fields calculated on the basis of a low incremental oil recovery factor. The split of the viable projects between the sectors is shown in Figure 4.28.

If the high price scenario is assumed the production of 90% of the incremental oil could be viable yielding 80 million barrels yearly, while avoiding 57 million tonnes of CO_2 per year. The potential for oil production and CO_2 storage is almost equally split between the sectors.

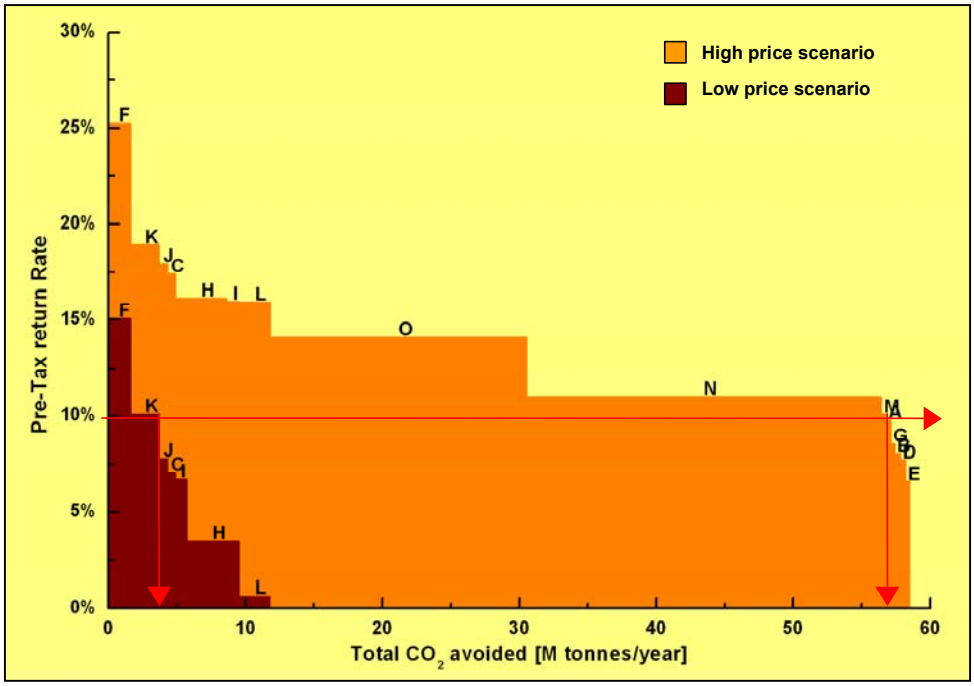

Figure 4.26: Potential cumulative CO_2 avoided depending on the project return rate acceptable for realisation. 1-year lag between CO_2 injection and oil production for all projects. Oil recovery at 4% and 10% of OOIP for miscible and immiscible projects respectively.

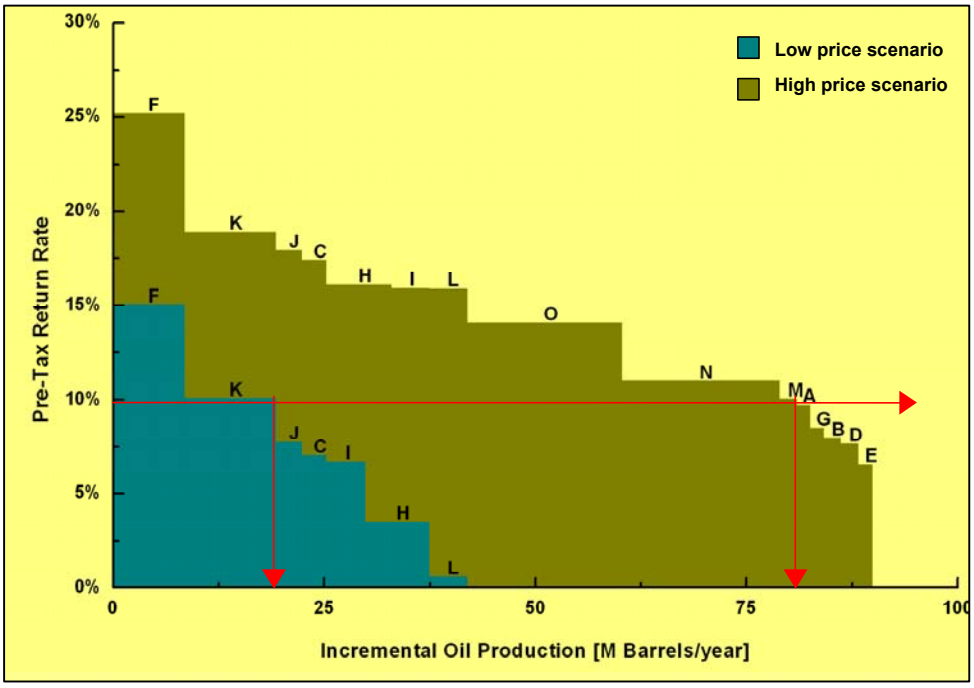

Figure 4.27: Potential cumulative incremental oil produced depending on the project return rate acceptable for realisation. 1-year lag between CO_2 injection and oil production for all projects. Oil recovery at 4% and 10% of OOIP for miscible and immiscible projects respectively.

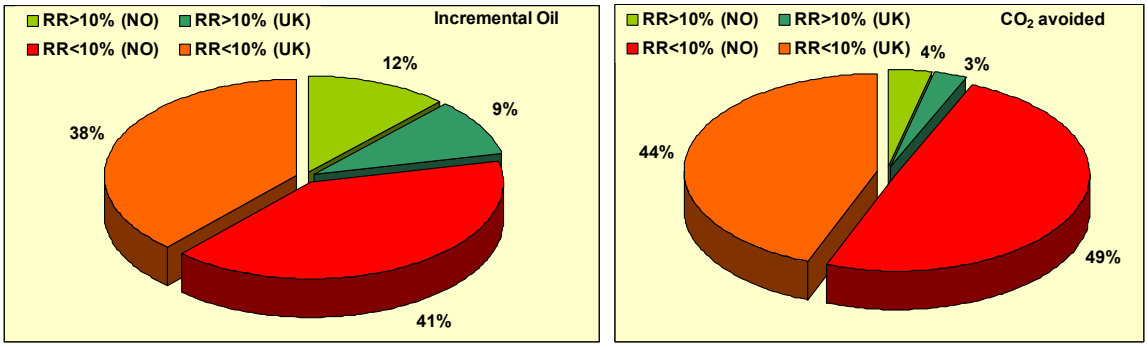

Figure 4.28: Distribution of total potential for incremental oil recovery and CO_2 avoided according to sector and project profitability. Plotted for the low price scenario and a discount rate of 10%. 1-year lag between CO_2 injection and oil production. Oil recovery at 4% and 10% of OOIP for miscible and immiscible projects respectively.

Figure 4.29 and Figure 4.30 show the financial gain or loss for each project normalised against the estimated incremental oil produced and amount of CO_2 avoided for the two price scenarios. The reduced oil recovery and CO_2 storage potential of miscible projects in this case means that a number of them is less attractive even when a high price scenario is assumed, while for a low price scenario most of the fields considered are non profitable and would operate as subsidised sinks for the 10% discount rate assumed as a threshold. The cost of storing CO_2 in this case is considerably higher than the estimates given in the previous section and might even prove higher than considering pure CO_2 storage options – without the EOR aspect.

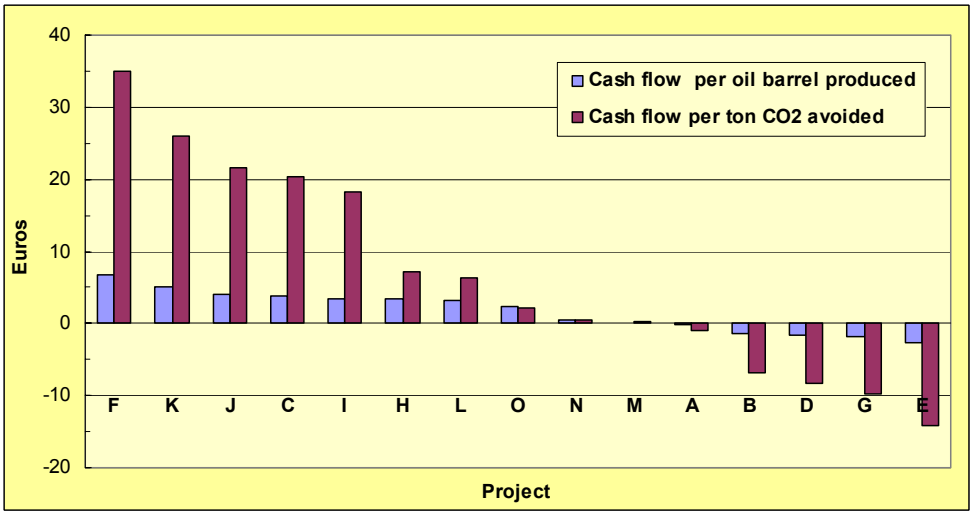

Figure 4.29: Average cash flow per incremental barrel of oil produced and tonne of CO_2 avoided over the project lifetime for the high price scenario. Discount rate assumed at 10%. 1-year lag between CO_2 injection and oil production for all projects. Oil recovery at 4% and 10% of OOIP for miscible and immiscible projects respectively.

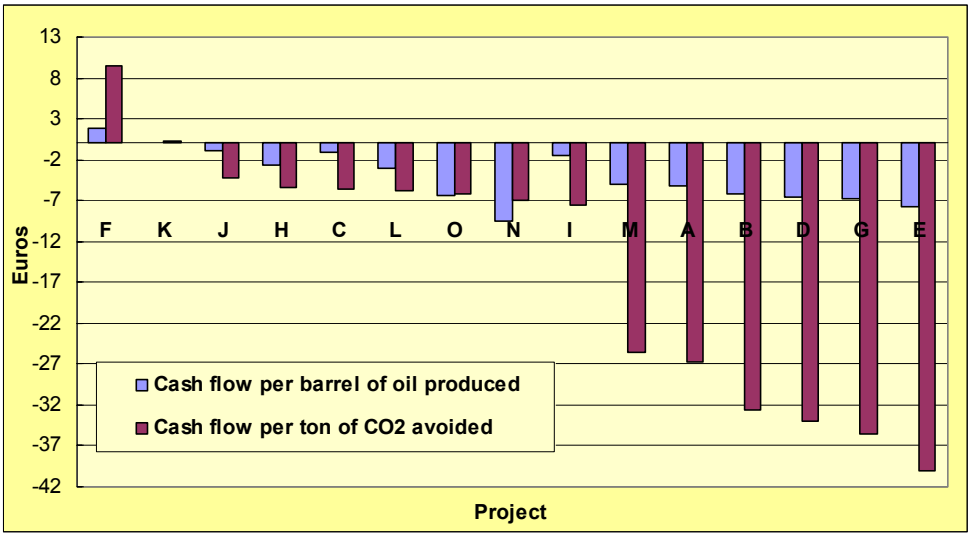

Figure 4.30: Average cash flow per incremental barrel of oil produced and tonne of CO_2 avoided over the project lifetime for the low price scenario. Discount rate assumed at 10%. 1-year lag between CO_2 injection and oil production for all projects. Oil recovery at 4% and 10% of OOIP for miscible and immiscible projects respectively.

For reference the capital expenditure for each project is plotted in Figure 4.31. As the assumed incremental oil production and CO_2 storage is halved compared to the results on the previous section, specific costs have doubled with respect to those plotted in Figure 4.23.

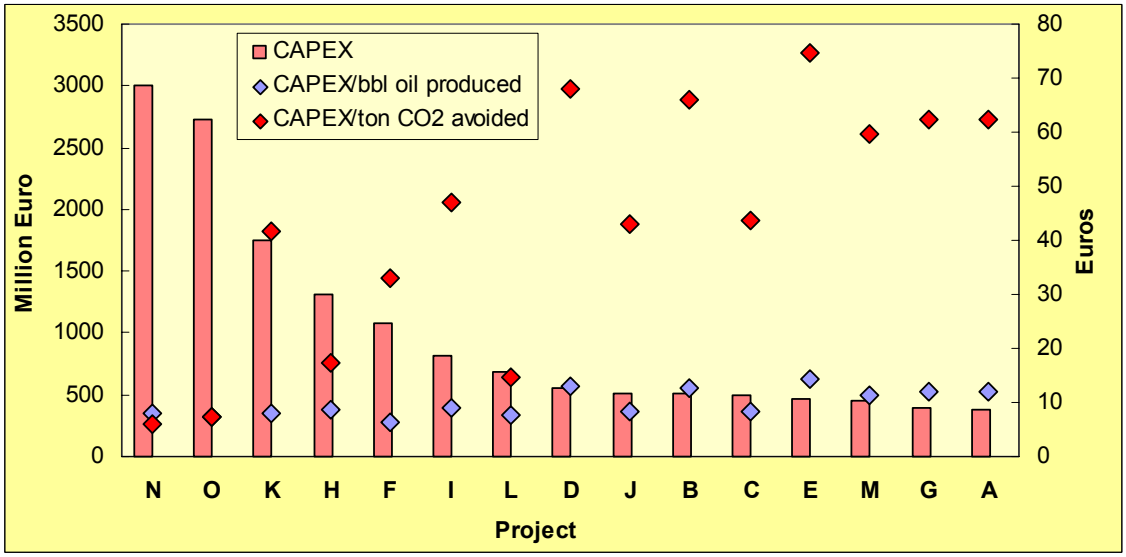

Figure 4.31: Capital expenditure for each project as an absolute sum and normalised against the incremental oil production expected and estimated CO_2 avoided throughout the project lifetime. Oil recovery at 4% and 10% of OOIP for miscible and immiscible projects respectively.

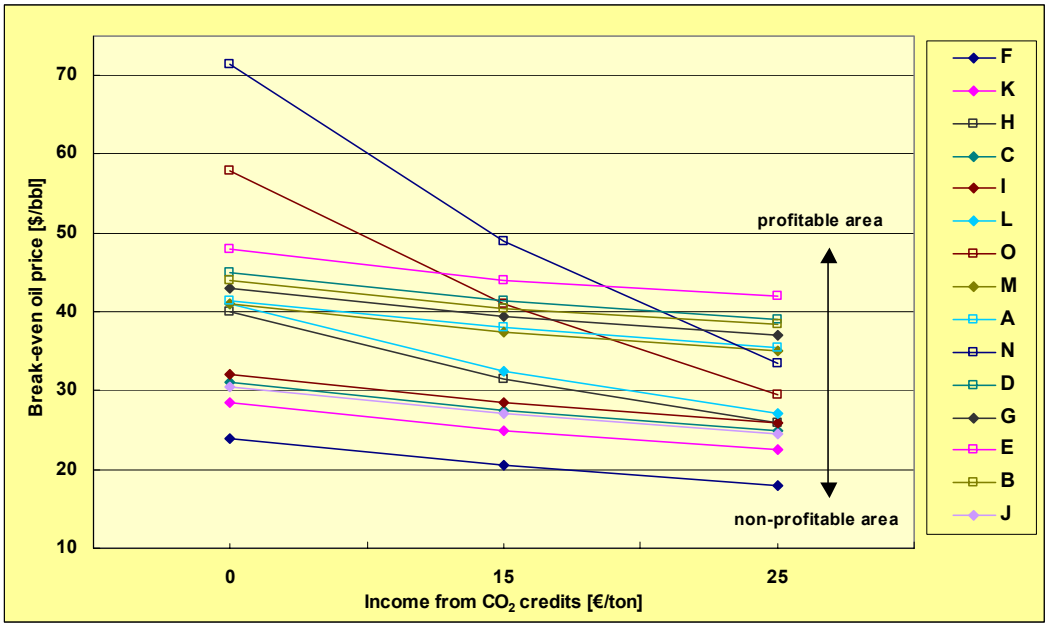

Figure 4.32: Break-even oil prices for the projects against CO_2 storage credits. Discount rate at 10%. 1-year lag between CO_2 injection and oil production. Oil recovery at 4% and 10% of OOIP for miscible and immiscible projects respectively.

Figure 4.32 shows the relationship between CO_2 credit prices and oil prices so that each project will be marginally viable – returning a net present value of zero. As marked on the plot the area under each line representing a project is a price combination area not favourable for investment, while the opposite is true if the predicted prices indicate a point over the project line. While these prices are higher than the ones plotted in Figure 4.24 where a higher incremental oil recovery was assumed, they are still comparable with oil market prices at the time of writing for the majority of the projects. However, as discussed previously the assumptions of this study differ considerably from those used by stakeholders during project evaluations.

The potential annual incremental oil production and annual CO_2 avoided through economically viable projects for the four different combinations of market prices and incremental oil recovery rates are summarised in Figure 4.33 and Figure 4.34. The EU oil production for 2003 and the UK CO_2 emission from power generation for the same year are also shown to put the results in to perspective. While CO_2-EOR could offer an increase of up to 18% to the annual EU oil production (based on 2003 figures), in terms of CO_2 mitigation it could only offer some benefit to the countries surrounding the North Sea.

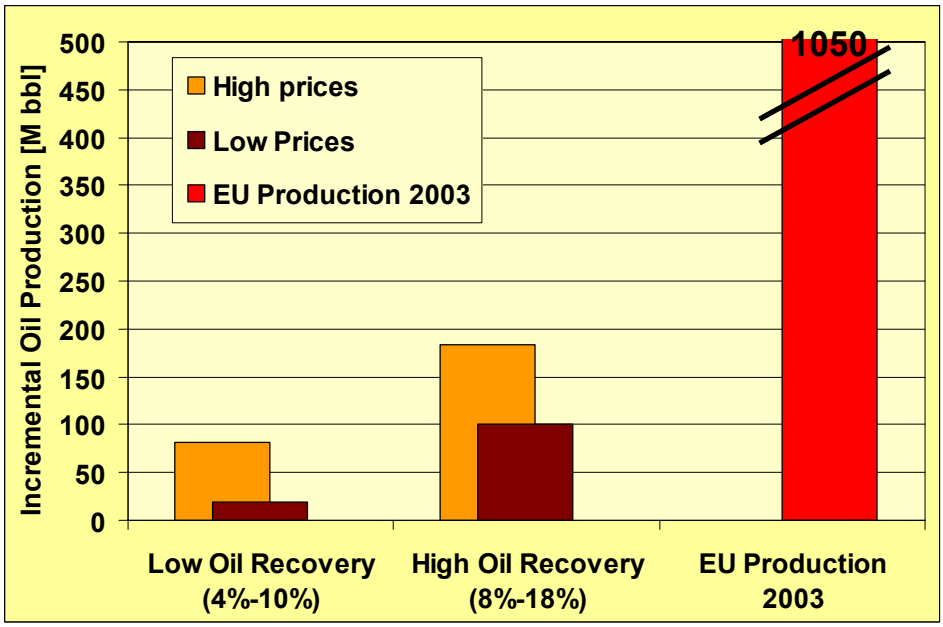

Figure 4.33: Annual incremental oil production from viable projects for different price scenarios and incremental oil recovery factors. The EU oil production for 2003 is shown for reference. Discount rate at 10%.

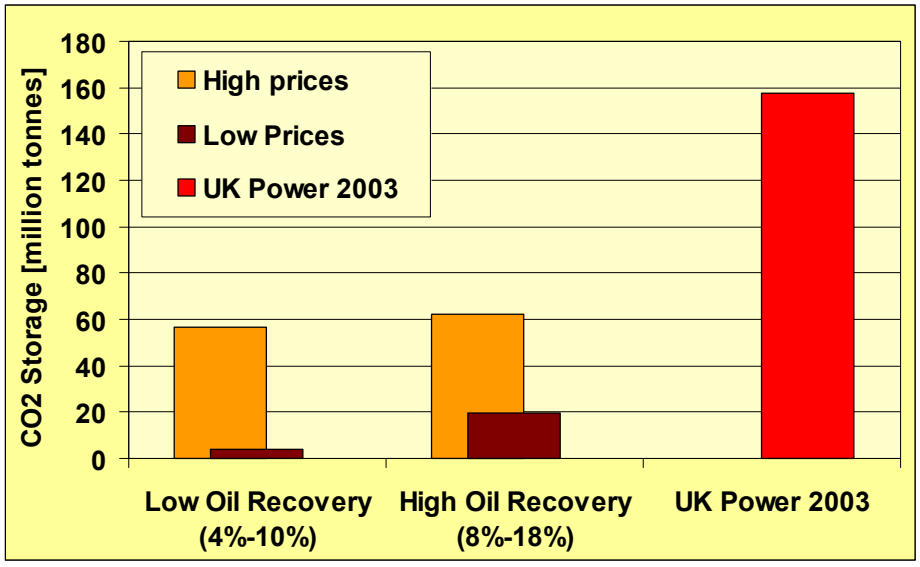

Figure 4.34: Annual CO_2 avoided from viable projects for different price scenarios and incremental oil recovery factors. The UK CO_2 emission from power generation for 2003 is shown for reference. Discount rate at 10%.

CO_2 injection continues after the end of oil production

For a number of the selected miscible projects the maximum potential capacity for CO_2 storage will not have been fulfilled by the time oil production by CO_2-EOR ceases. For these fields the option of continuing CO_2 injection at the same rate was examined. The assumption is that the decommissioning of the facility is postponed until the maximum storage capacity for CO_2 is reached. The timescale varies from extending operation by 7 years for fields with small storage potential, up to a theoretical 84 years for the larger sinks. The increase in the amount of CO_2 avoided compared to the results presented in the previous section for oil recovery factors of 9% of OOIP for each field is displayed in Figure 4.35. Overall, only 26% of the potential will have been used up by the end of oil production if standard practices are used. If low incremental oil recovery (4% of OOIP) is assumed then the figures for CO_2 already avoided will be almost half of the ones shown here, and the timeframe slightly larger.

It has been suggested that at this point the infrastructure from these projects could be moved to serve other fields, as it may not have reached the end of its useful life. This would also aid the project economics, as the remaining value of the infrastructure will be another asset providing income at the end of the project and offsetting some of the decommissioning costs. Here it is assumed that the infrastructure is kept in use for an extended period of time to continue CO_2 injection and then decommissioned.

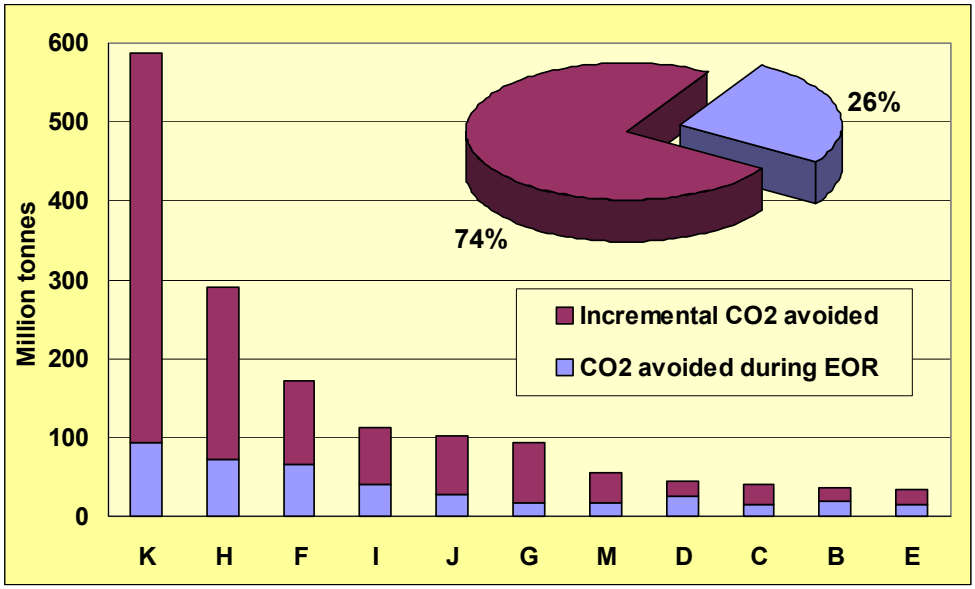

Figure 4.35: Potential for CO_2 avoided during CO_2-EOR (incremental oil recovery at 9% of OOIP) and by continuing injection past the end of oil production for miscible projects.

For the economic evaluation, operation and maintenance costs are changed to reflect the fact that there is no oil production. Therefore, instead of the fields' operation and maintenance cost used for the 20-year oil producing period an average cost of €10 per tonne for CO_2 storage is assumed. This cost reflects an average of the costs for offshore CO_2 storage as reported by Hendriks *et al* (7-16$/ton) [82]. The cost of acquiring CO_2 at the plant gate is maintained, as is the income from CO_2 credits. Since the CO_2 credit assumed at €15-25/tonne is lower than the CO_2 cost of €25.2/tonne (see Table 4.10) at the plant the project operates at a loss for this extended period of injection. For this period there are no losses from CO_2 breakthrough and recycling, and there is a benefit from deferring the substantial decommissioning costs to a later date.

Figure 4.36 and Figure 4.37 show the difference in the net present value of the projects calculated on the basis of a 10% discount rate – NPV(10) – for the low and high price scenario in the case that injection is continued past the end of oil production for the purpose of further CO_2 storage. The effect of the extension of the projects is not big enough to influence the overall viability, and in the case of the high price scenario the income from CO_2 credits means that there is only an 2% difference in total in the net present value of the projects while 1160 million tonnes could be avoided by continuing the injection process. For the low case scenario if injection continues in projects that are viable given the 10% discount rate assumed an extra 967 million tonnes of CO_2 may be avoided. However, the income reduction amounts to 17% in total of the profit estimated in the case of high incremental oil recovery, which is quite significant.

If we re-calculate these figures assuming that only 4% of the OOIP is recovered instead of the previous 9% estimate, then for a low price scenario all projects are showing losses and operate like subsidised sinks, as previously displayed in Figure 4.30. Although the losses for the projects increase, the average cost of storing CO_2 in them decreases as it is spread over larger CO_2 quantities and time, but this is more of a theoretical calculation on the cost of a CO_2 storage project, rather than a CO_2-EOR operation, as the latter is non viable. However, the case is different if a high price scenario is assumed, when about half the project display good – but somewhat reduced results as shown in Figure 4.38.

Results are presented in detail in Appendix IV.

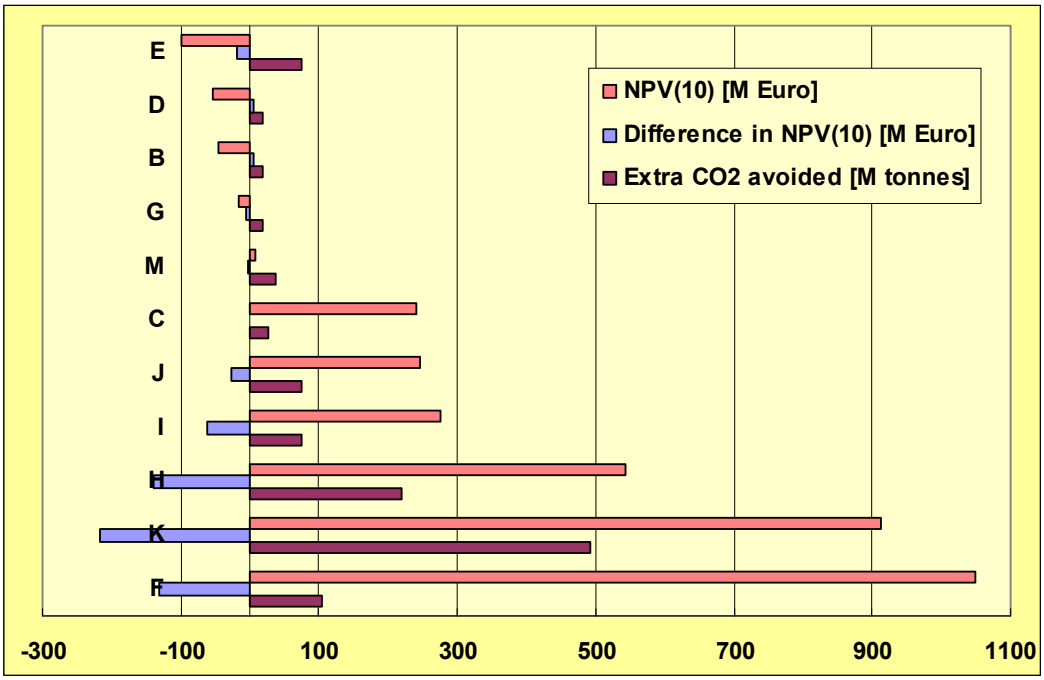

Figure 4.36: Difference in the economics and potential CO_2 avoided by continuing injection at the end of oil production. Low price scenario. 1-year lag between CO_2 injection and oil production. Oil recovery at 9% of OOIP.

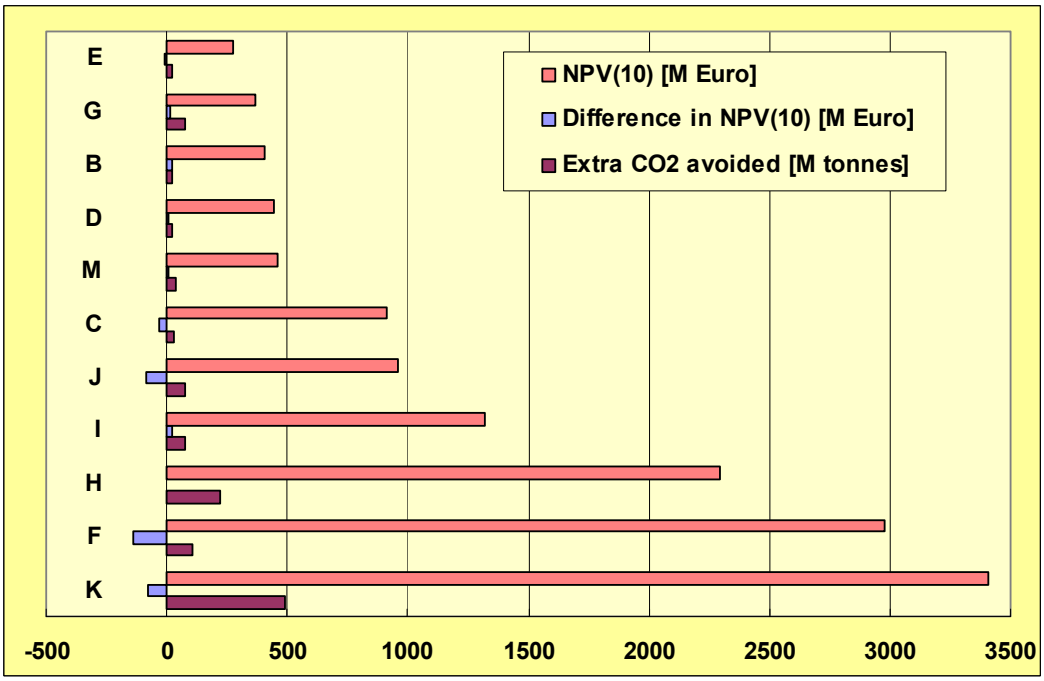

Figure 4.37: Difference in the economics and potential CO_2 avoided by continuing injection at the end of oil production. High price scenario. 1-year lag between CO_2 injection and oil production. Oil recovery at 9% of OOIP.

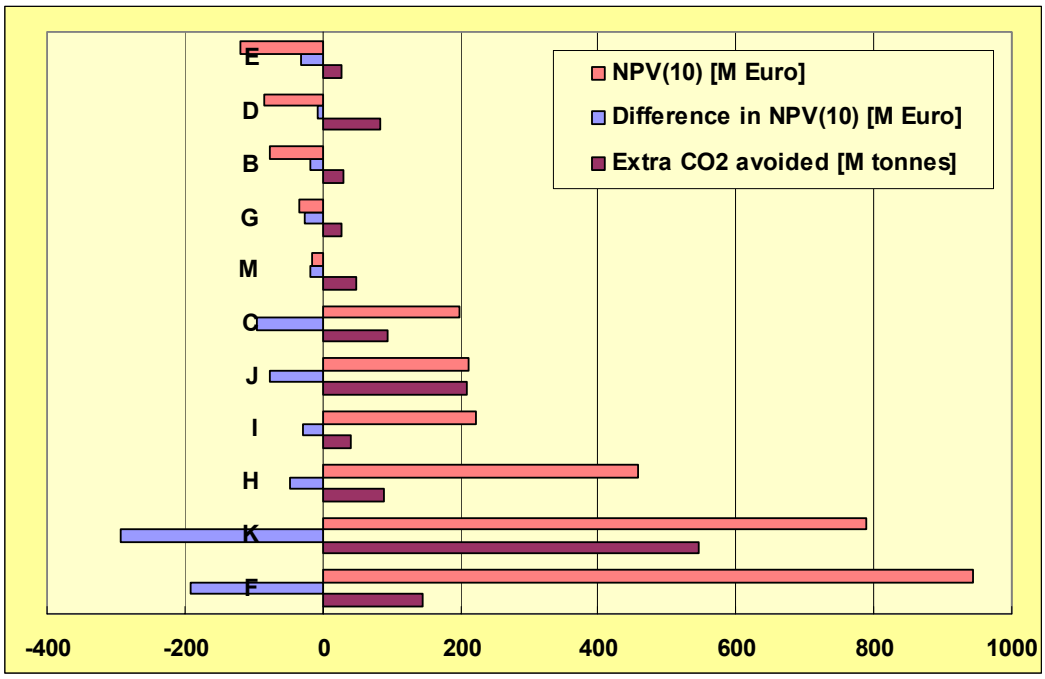

Figure 4.38: Difference in the economics and potential CO_2 avoided by continuing injection at the end of oil production. High price scenario. 1-year lag between CO_2 injection and oil production. Oil recovery at 4% of OOIP.

Maximum CO_2 injection during oil production

As previously mentioned, due to high prices of CO_2-EOR projects are designed to minimise the use of CO_2 and possibly recover CO_2 quantities at the end of the project. However, they could be designed to maximise CO_2 use and storage under circumstances that would make this type of operation profitable. While keeping most of the previous assumptions made for the operation of the projects on selected fields, a scenario was examined where the CO_2 amount injected corresponded to the quantity required so that the sink would reach its maximum storage potential after a 20 year EOR operation. At this point it is assumed that the incremental oil production stops and the field is sealed off and decommissioned.

It should be noted that, while we assume that the maximum CO_2 storage potential can be reached during this process, this potential might be reduced due to the increased rates of CO_2 injection. Research published by Holt *et al* [83] states that the CO_2 storage capacity depends on the injection rate and may reach a constant lower limit as injection rates (expressed as a percentage of the well pore volume per year) increase.

For this scenario the pipeline costs are recalculated to accommodate the increased amount of CO_2 transported but also to account for the fact that a different source or multiple sources may be needed to cover the increased CO_2 needs. As with the base case, coal power plants are preferable CO_2 sources but natural gas plants are also included in some of the projects. All relevant quantities (e.g. CO_2 price, CO_2 avoided etc.) have been proportionally adjusted for the inclusion of natural gas plants for each

project. To account for increased expenses incurred due to the higher amounts of CO_2 processed, the operating cost of €10 per extra tonne of CO_2 stored is assumed as in the case of continuing CO_2 injection after the end of oil production.

In absence of detailed reservoir modelling that would give an indication of the field behaviour during this type of operation and for the sake of simplicity and consistency all other assumptions noted for the case of applying standard practices (minimum required CO_2 volume) are maintained here. It is recognised however that these assumptions become more uncertain.

For the low price scenario no projects are viable under these assumptions. For the high price scenario a number of projects return a net present value which is positive, but significantly reduced from the results obtained for the case of minimum CO_2 injection. On aggregate the reduction is over 50% of the gains calculated for the projects when standard practices of CO_2 injection were assumed.

Figure 4.39 and Figure 4.40 show the performance in economic terms of the different projects for the three options regarding CO_2 injection as described in previous paragraphs. When a result is displayed for the option for continued injection but not for the maximum injection case this means that the project is displaying losses. Figure 4.41 presents the same comparison for the case that only 4% of the OOIP is recovered by CO2-EOR and a high price scenario is assumed.

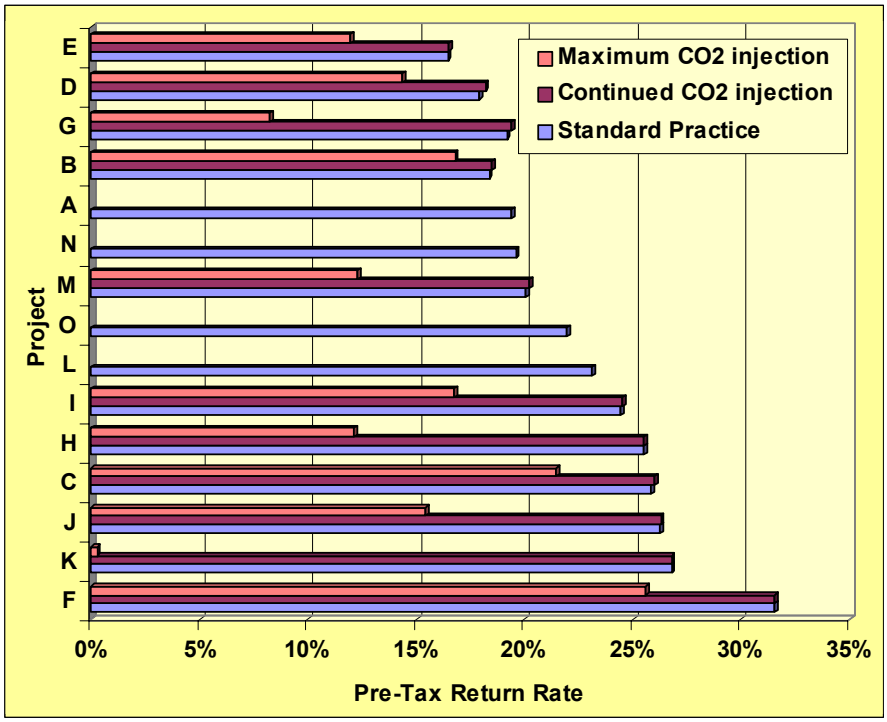

Figure 4.39: Comparison of the Pre-Tax Return Rates for all projects according to the CO_2 injection scheme selected for the high price scenario, 1-year lag between CO_2 injection and oil production and oil recovery at 9% of OOIP.

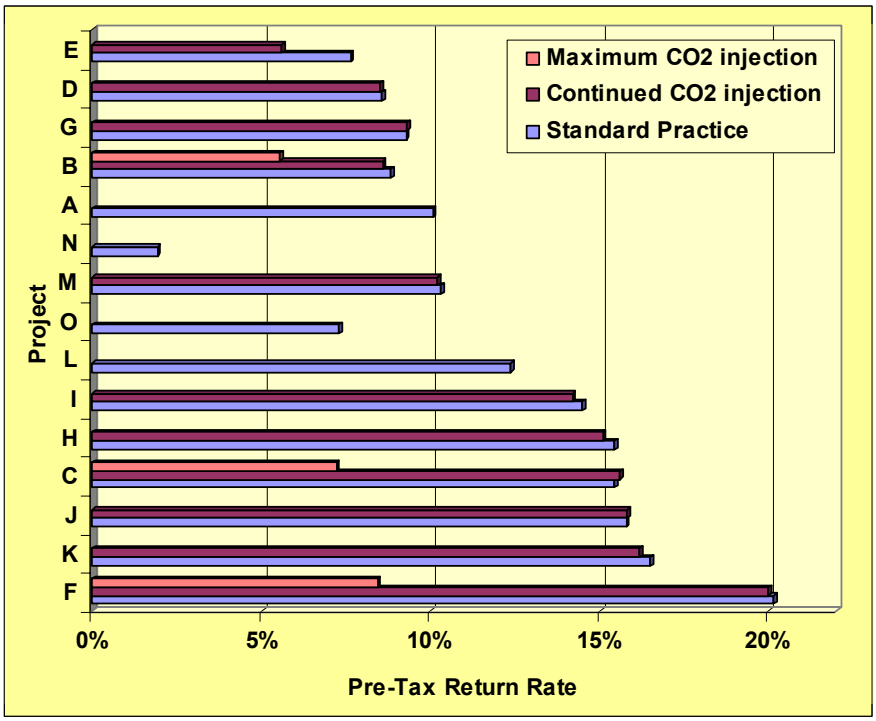

Figure 4.40: Comparison of the Pre-Tax Return Rates for all projects according to the CO_2 injection scheme selected for the low price scenario, 1-year lag between CO_2 injection and oil production, and oil recovery at 9% of OOIP.

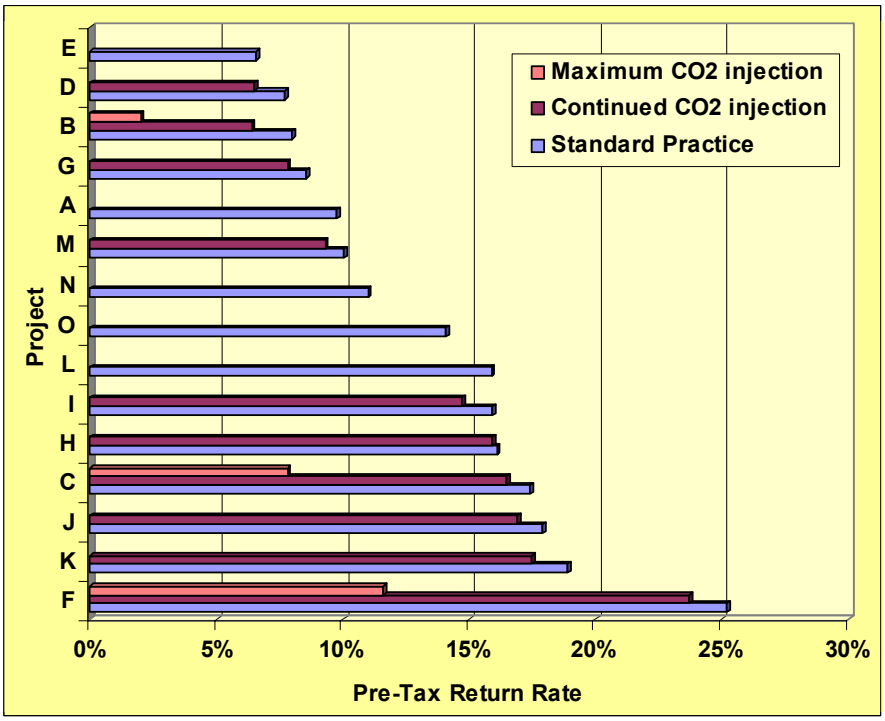

Figure 4.41: Comparison of the Pre-Tax Return Rates for all projects according to the CO_2 injection scheme selected for the high price scenario, 1-year lag between CO_2 injection and oil production and oil recovery at 4% of OOIP.

Integrated Network

The case of an integrated network comprising all the selected fields in a single project was also examined. Since the minimum CO_2 demand has to be met simultaneously for all fields a larger amount of sources was incorporated in this project including a number of natural gas plants. About 30% of the CO_2 in this scenario is provided by natural gas power plants and all relevant quantities (e.g. CO_2 price, CO_2 avoided etc.) have been adjusted to reflect this change by the use of weighted averages. The pipeline network has been recalculated to take into account the different CO_2 quantities delivered to the field clusters. All other assumptions are maintained as for the cafe ofapplying standard practices (minimum required CO_2 volume) and the values entered in the calculation for field infrastructure, oil yield etc. are the aggregate sums of those estimated for individual projects. The main figures for this project are given in Table 4.13.

A project comprising 12 fields in the North Sea as described in the CENS [85] project estimates a production of 2.1 billion barrels of incremental oil while storing 680 Mt of CO_2. However, a number of the assumptions for this project are different, including the recovery rate for incremental oil, which is set at 6% of the OOIP. The reservoirs selected also differ, although 8 of the fields are common in both projects.

Table 4.13:Main assumptions and results for the integrated network project

	Incremental oil recovery		
	9%OOIP	*4%OOIP*	
CO_2 required	108	97.2	Mt per annum
Pipeline length	5166	5166	km
Pipeline cost	6943	6943	M €
CAPEX	15477	15477	M €
Incremental Oil	3812	1799	M Barrels
or	190	90	M bbl per annum
CO_2 avoided	1311	1158	M tonnes
or	65	59	Mt per annum
IRR (%)	14.2	LOSS	Low Scenario
	25.1	14.0	High Scenario

4.5.3 In Summary

Assuming a high incremental oil recovery factor and current oil prices almost all of the 15 considered projects could be considered for further evaluation. For a number of fields a CO_2-EOR project could be viable even without a carbon-trading scheme. However, smaller fields in terms of oil production and CO_2 storage potential and projects requiring large initial investments are more likely to suffer when pricing is less favourable and are therefore the ones which can withstand less risk.

For a low incremental oil recovery factor, while higher oil prices are necessary to ensure the viability for the majority of the projects, they are still comparable with current oil market prices, at the time of writing.

If standard practices are applied, CO_2-EOR in viable projects in the selected fields examined could offer an increase of up to 18% to European oil production. However, in terms of CO_2 mitigation, CO_2-EOR could only offer a small benefit to the countries surrounding the North Sea.

In the case of continued injection after the end of oil production, if the CO_2 credit is lower than the cost of CO_2 supply at power plant gate, the project operates at a loss for this extended period of CO_2 injection. However, in the majority of cases the effect of the extension of project life is not big enough to influence the overall viability. In the case of high CO_2 prices the decrease in the net present value of the projects is smaller. More substantial income reduction is observed for low prices of oil and CO_2 credits during the oil recovery lifetime of the project.

In contrast to continuing CO_2 injection after the end of oil production, injecting larger volumes of CO_2 from the start of the project in order to reach maximum CO_2 storage potential within a shorter time frame is detrimental to project economics.

In all cases there is a benefit from deferring the substantial decommissioning costs to a later date.

5 Conclusions

- CO_2-EOR is a commercial technology, implemented onshore in other parts of the world. However, such projects are not implemented in Europe.
- The existing knowledge may not be directly applicable to the European oil reservoirs, due to the different geological characteristics and the offshore location of most of them. Preliminary reservoir modelling tends to support that the oil recovery rates that are likely to be achieved in oilfields in the North Sea are lower that those observed in the USA.
- CO_2-EOR can increase considerably the European oil production and hence improve the security of oil supply within the EU. However, competing EOR methods may limit the application of the technique.
- The impact of CO_2-EOR to reduce GHG emissions, however, will be limited to CO_2 sources in the vicinity of the oil fields. Hence, the benefit would be restricted to a liming number of countries, mainly around the North Sea.
- The knowledge gained by the implementation of CO_2-EOR projects in the North Sea could be beneficial for other CO_2 geological storage projects at the pan-European level, a prerequisite for the development of decarbonised fossil fuel power plants.
- There are no major technical barriers to the implementation of CO_2-EOR projects onshore. Offshore projects however will have to overcome challenging economic and operating conditions. Hence, the applicability of CO_2-EOR should be considered individually for each reservoir.
- The main barriers to the implementation in Europe include the lack of low cost CO_2 supply, the high expenses associated with offshore operations (including modifications to the existing infrastructure), the unclear situation concerning the eligibility for financial incentives for CO_2 storage, followed by concerns about the permanence and safety of CO_2 storage.
- Due to the fact that many reservoirs in the North Sea are reaching their end of conventional production life, a decision for the implementation of CO_2-EOR projects should be taken within the next 10 years.
- There are no legal barriers for the use of CO_2 in EOR projects. Legal uncertainties, however, surround the injection of CO_2 underground for storage purposes.
- It appears that under the current oil and CO_2 pricing conditions, a number of financially viable CO_2-EOR projects could be implemented, provided that CO_2-EOR can benefit from financial incentives for CO_2 storage.
- Annual oil production in selected economically viable projects may reach 180 million barrels with the simultaneous storage of 60 million tonnes of CO_2, under favourable oil and CO_2 prices and optimal oil recovery rates.

Acknowledgments

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Appendix I: Oil composition and properties

Table I.1: Typical composition and properties of crude oils [84]

Crude oil	*Paraffins*[31] *(% vol.)*	*Aromatics*[32] *(%vol.)*	*Napthenes*[33] *(%vol.)*	*API gravity*	*Sulphur (%wt.)*
North Sea Brent	50	16	34	37	0.4
Saudi Light	63	19	18	34	2.0
Saudi Heavy	60	15	25	28	2.1
Venezuela Heavy	35	12	53	30	2.3
Venezuela Light	52	14	34	24	1.5
USA W. Texas Sour	46	22	32	32	1.9
Nigerian Light	37	9	54	36	0.2

[31] Paraffins are saturated hydrocarbons with a generic formula C_nH_{2n+2}.

[32] Aromatics are unsaturated hydrocarbons with at least one benzene ring.

[33] Napthenes are cyclic saturated hydrocarbons.

Appendix II: CO_2 Capture and Electricity Costs

Table II.1: Data for a reference natural gas (GTCC) power plant versus a CO_2 capture equivalent [4].

REFERENCE PLANT			*PLANT WITH CO2 CAPTURE*		
Capital charge rate	10	%			
Yearly operation	7884	hours	**Capture Plant Cost**	462	million €
Capacity factor	90.0	%	**SCI**	998	€/kW
Investment Cost	536	€/kW	**Capture Efficiency**	90	%
Plant Efficiency (LHV)	55.4	%	**Plant efficiency**	48.2	%
Power output	500	MWe			
Fuel Cost	5.5	€/GJ	**CO_2 generation**	1.67	M tonnes
Maintenance factor	2	%	**CO_2 captured**	1.50	M tonnes
CO_2 Emittance	369	kg/MWh	**CO_2 emittance**	42.4	kg/MWh
			CO_2 removal	381.7	kg/MWh
CO_2 emitted	1.45	M tonnes	**CO_2 emitted**	0.17	M tonnes
Power Output	3.94E+03	M kWh	**Power Output**	3.94E+03	M kWh
Fuel Requirement	7.12E+03	M kWh	**Fuel Requirement**	8.18E+03	M kWh
Annual Fuel Input	2.56E+07	GJ	**Annual Fuel Input**	2.94E+07	GJ
Annual Fuel Cost	140.89	M €	**Annual Fuel Cost**	161.93	M €
Total Capital Cost	268.00	M €	**Total Capital Cost**	499	M €
O&M Annual Cost	16.08	M €	**O&M Annual Cost**	29.94	M €
			Increased fuel consumption	14.9	%
Cost of Electricity			**Cost of Electricity**		
capital investment	0.68	c/kWh	***capital investment***	1.27	c/kWh
fuel	3.57	c/kWh	***fuel***	4.11	c/kWh
O&M	0.41	c/kWh	***O&M***	0.76	c/kWh
Total	4.66	c/kWh	**Total**	6.13	c/kWh
Incr.Cost of Electricity	1.47	c/kWh	**Cost of CO_2 avoided**	45.06	€/t CO2
OR	31.56	%	**Cost of CO_2 captured**	38.55	€/t CO2

Table II.2: Data for a reference coal (SC) power plant versus a CO_2 capture equivalent according to [4].

REFERENCE PLANT			*PLANT WITH CO2 CAPTURE*		
Capital charge rate	10	%			
Yearly operation	7446	hours	**Capture Plant Cost**	825	million €
Capacity factor	85.0	%	**SCI**	1976	€/kW
Investment Cost	1151	€/kW	**Capture Efficiency**	90	%
Plant Efficiency (LHV)	41.8	%	**Plant efficiency**	31.4	%
Power output	500	MWe			
Fuel Cost	2	€/GJ	**CO_2 generation**	3.85	M tonnes
Maintenance factor	5	%	**CO_2 captured**	3.46	M tonnes
CO_2 Emittance	776	kg/MWh	**CO_2 emittance**	103.3	kg/MWh
			CO_2 removal	927.7	kg/MWh
CO_2 emitted	2.89	M tonnes	**CO_2 emitted**	0.38	M tonnes
Power Output	3.72E+03	M kWh	**Power Output**	3.72E+03	M kWh
Fuel Requirement	8.91E+03	M kWh	**Fuel Requirement**	1.19E+04	M kWh
Annual Fuel Input	3.21E+07	GJ	**Annual Fuel Input**	4.27E+07	GJ
Annual Fuel Cost	64.13	M €	**Annual Fuel Cost**	85.37	M €
Total Capital Cost	575.50	M €	**Total Capital Cost**	988	M €
O&M Annual Cost	51.80	M €	**O&M Annual Cost**	76.545	M €
			Increased fuel consumption	33.1	%
Cost of Electricity			**Cost of Electricity**		
capital investment	1.55	c/kWh	***capital investment***	2.65	c/kWh
fuel	1.72	c/kWh	***fuel***	2.29	c/kWh
O&M	1.39	c/kWh	***O&M***	2.06	c/kWh
Total	4.66	c/kWh	**Total**	7.00	c/kWh
Incr.Cost of Electricity	2.34	c/kWh	**Cost of CO_2 avoided**	34.83	€/t CO_2
OR	50.29	%	**Cost of CO_2 captured**	25.2	€/t CO_2

Appendix III: Source – sink combinations for the different projects

Table III.1: Indicative source-sink combinations used as examples in the study

Field (sink)	*Base case (min. CO_2 supply)*		*Maximum CO_2 storage*	
	Project	Source(s)	Project	Source(s)
Auk	A	Cockenzie		
Brage	B	Cockenzie	B	Cockenzie
Claymore	C	Cockenzie	C	Longannet
N Cormorant	D	Cockenzie	D	Longannet
Dunlin	E	Cockenzie	E	Cockenzie
Forties	F	Longannet	F	Peterhead, Cockenzie, Longannet
Fulmar	G	Cockenzie	G	Drax
Gullfaks	H	Longannet	H	Drax, Cockenzie, Longannet
Ninian	I	Longannet	I	Longannet
Piper	J	Cockenzie	J	Longannet
Statfjord	K	Longannet	K	Drax, Cockenzie, Longannet, Teeside, Eggborough, Peterhead
Tor	L	Drax		
Ula	M	Cockenzie	M	Longannet
Brent	N	Drax, Eggborough, Cockenzie, Longannet, Ferrybridge		
Oseberg	O	Drax, Eggborough, Cockenzie, Longannet		
Integrated Network, All fields		Fynsværket, Vendsysselværket, Studstrupværket, Enstedværket, Asnæsværket, Amercentrale, Gelderland, Hemweg, Wilhelmshaven, Eems, Ibbenbüren, Bergum, Meppen, Peterhead, Cockenzie, Longannet, Immigham, Eggborough, West Burton, Ferrybridge C, Ratcliffe-on-Soar, Drax, Killingholme A, Saltend, Cottam (LPCP), South Humber Bank, Keadby 1, Sutton Bridge, Killingholme PG1, Teesside		

Appendix IV: Results from the economic assessment

Table IV.1: Results of the techno economic assessment for the selected fields and a high incremental oil recovery assuming a high and low case scenario for oil and carbon trading prices. Stand alone projects with CO_2 provided by dedicated pipeline transport from the nearest source.

			Per Year		*Project Life (20 years)*		*Low Scenario*		*High Scenario*	
Project	*Field*	*CAPEX*	*Increment. Oil*	*CO_2 avoided*	*Increment. Oil*	*CO_2 avoided*	*IRR*	*NPV(10)*	*IRR*	*NPV(10)*
		M €	*M Barrels*	*M tonnes*	*M Barrels*	*M tonnes*		*M €*		*M €*
A	Auk	379	3.6	0.7	71.6	13.8	10.1%	2	19.4%	357
B	Brage	504	4.5	0.9	89.8	17.3	8.8%	-43	18.4%	402
C	Claymore	489	6.5	1.3	131.0	25.2	15.4%	242	25.9%	891
D	N Cormorant	559	4.8	0.9	96.5	18.6	8.6%	-58	17.9%	421
E	Dunlin	472	3.7	0.7	47.3	14.3	7.6%	-82	16.5%	286
F	Forties	1073	18.9	3.7	378.0	73.0	20.2%	1180	31.6%	3053
G	Fulmar	395	3.7	0.7	74.3	14.3	9.3%	-20	19.2%	348
H	Gullfaks	1306	17.1	3.3	342.2	66.0	15.4%	684	25.5%	2380
I	Ninian	822	10.2	2.0	203.9	39.3	14.5%	338	24.5%	1348
J	Piper	512	7.0	1.4	139.7	26.9	15.8%	273	26.3%	966
K	Statfjord	1745	24.4	4.7	487.4	94.1	16.5%	1131	26.8%	3546
L	Tor	686	8.1	2.1	162.0	42.8	12.4%	141	23.1%	990
M	Ula	454	4.5	0.9	89.1	17.2	10.3%	11	20.0%	453
N	Brent	3008	33.7	22.6	673.7	452.1	1.9%	-1848	19.6%	3123
O	Oseberg	2729	33.0	16.8	660.2	335.8	7.3%	-634	22.0%	3683

Table IV.2: Results of the techno economic assessment for the selected fields and a low incremental oil recovery assuming a high and low case scenario for oil and carbon trading prices. Stand alone projects with CO_2 provided by dedicated pipeline transport from the nearest source.

			Per Year		Project Life (20 years)		Low Scenario		High Scenario	
Project	*Field*	*CAPEX*	*Increment. Oil*	*CO_2 avoided*	*Increment. Oil*	*CO_2 avoided*	*IRR*	*NPV(10)*	*IRR*	*NPV(10)*
		M €	*M Barrels*	*M tonnes*	*M Barrels*	*M tonnes*		*M €*		*M €*
A	Auk	379	1.6	0.3	31.8	6.1	-	-163	9.8%	-5
B	Brage	504	2.0	0.4	39.9	7.7	-	-250	8.0%	-52
C	Claymore	489	2.9	0.6	58.2	11.2	7.1%	-62	17.4%	227
D	N Cormorant	559	2.1	0.4	42.9	8.2	-	-280	7.7%	-67
E	Dunlin	472	1.7	0.3	33.0	6.3	-	-253	6.6%	-89
F	Forties	1073	8.4	1.6	168.0	32.4	15.1%	304	25.2%	1137
G	Fulmar	395	1.7	0.3	33.0	6.3	-	-192	8.5%	-28
H	Gullfaks	1306	7.6	3.8	152.1	75.2	3.5%	-403	16.1%	532
I	Ninian	822	4.5	0.9	90.6	17.4	6.7%	-132	15.9%	317
J	Piper	512	3.1	0.6	62.1	12.0	7.8%	-50	17.9%	257
K	Statfjord	1745	10.8	2.1	216.6	41.8	10.1%	9	18.9%	1082
L	Tor	686	4.5	2.3	90.0	46.3	0.6%	-271	15.9%	290
M	Ula	454	2.0	0.4	39.6	7.6	-	-195	10.1%	2
N	Brent	3008	18.7	25.9	374.3	505.8	-	-3561	11.0%	213
O	Oseberg	2729	18.3	18.7	366.8	374.1		-2313	14.1%	831

Table IV.3: Results of the techno economic assessment for the selected fields assuming a high and low case scenario for oil and carbon trading prices, and ongoing injection after the end of oil production. Stand alone projects with CO_2 provided by dedicated pipeline transport from the nearest source. High oil Recovery.

Project	*Field*	*Project Duration*	*Incremental CO_2 avoided*	*Low Scenario*		*High Scenario*	
				IRR	*NPV(10)*	*IRR*	*NPV(10)*
		Years	*M te*		*M €*		*M €*
B	Brage	27	18	8.6%	-47	18.5%	405
C	Claymore	37	27	15.6%	241	26.0%	916
D	NCormorant	37	19	8.5%	-53	18.2%	444
E	Dunlin	41	105	5.6%	-100	16.5%	279
F	Forties	43	75	20.0%	1048	18.2%	330
G	Fulmar	70	219	7.7%	-50	31.6%	2977
H	Gullfaks	73	20	15.1%	544	25.5%	2296
I	Ninian	50	74	14.2%	276	24.5%	1319
J	Piper	64	74	15.8%	246	26.3%	962
K	Statfjord	104	493	16.2%	913	26.8%	3410
M	Ula	56	39	10.2%	7	20.2%	463

Table IV.4: Results of the techno economic assessment for the selected fields assuming a high and low case scenario for oil and carbon trading prices, and injection of increased amounts of CO_2 in order to reach the maximum storage capacity of the reservoir within 20 years of operation. Stand alone projects with CO_2 provided by dedicated pipeline transport from the nearest source. High Oil Recovery.

Project	*Field*	*Incremental CO_2 avoided*	*Low Scenario*		*High Scenario*	
			IRR	*NPV(10)*	*IRR*	*NPV(10)*
		M te		*M €*		*M €*
B	Brage	8	5.5%	-150	16.8%	327
C	Claymore	28	7.2%	-109	21.5%	650
D	N Cormorant	20	-	-358	12.0%	88
E	Dunlin	111	8.4%	-156	25.6%	2145
F	Forties	46	-	-610	8.2%	-61
G	Fulmar	221	-	-2241	12.1%	334
H	Gullfaks	19	-	-324	14.4%	232
I	Ninian	76	-	-663	16.8%	649
J	Piper	76	-	-672	15.4%	321
K	Statfjord	518	-	-6323	0.3%	-1939
M	Ula	39	-	-496	12.3%	101

Table IV.5: Results of the techno economic assessment for the selected fields assuming a high and low case scenario for oil and carbon trading prices, and ongoing injection after the end of oil production. Stand alone projects with CO_2 provided by dedicated pipeline transport from the nearest source. Low Oil Recovery.

		Project	*Incremental*	*Low Scenario*		*High Scenario*	
Project	*Field*	*Duration Years*	*CO_2 avoided M te*	*IRR*	*NPV(10) M €*	*IRR*	*NPV(10) M €*
B	Brage	27	18	-	-330	6.4%	-78
C	Claymore	37	27	-	-181	16.5%	198
D	NCormorant	37	19	-	-364	6.5%	-85
E	Dunlin	41	105	-	-334	-	-120
F	Forties	43	75	-	-145	23.7%	945
G	Fulmar	70	219	-	-250	7.8%	-35
H	Gullfaks	73	20	-	-536	15.9%	457
I	Ninian	50	74	-	-367	14.7%	223
J	Piper	64	74	-	-195	16.9%	211
K	Statfjord	104	493	-	-624	17.5%	790
M	Ula	56	39	-	-274	9.3%	-16

Appendix V: Summary of assumptions for the CO_2 pipelines

The pipeline specifics and capital costs were calculated according to the IEA Greenhouse gas R&D programme report on "Transmission of CO_2 and Energy" [72]. The technical and economic input parameters are given in summary below:

- **Mass rate:** CO_2 amount assumed for each case
- **Terrain**: set as <20% mountainous
- **Length:** measured over the existing natural gas pipelines.
- **Pipeline inlet pressure**: 110 bar / 140 bar
- **Number of Booster Stations (BS)**: one for each onshore collection point for the integrated network project, and projects which require multiple CO_2 sources.
- **BS Pressure outlet**: 140 bar.
- **Diameter:** the pipeline diameter is selected to satisfy the outlet pressure criteria
- **Pipeline outlet pressure:** over 84 bar
- The hydraulic design criterion for these pipelines is that the velocity at the pipeline outlet is under 20m/s (when no BS is used).
- The piping class used is an ANSI Class 600#.
- The **Annual Capital Charge Factor** is set to 1
- The **Load Factor** is set to 100%
- The **exchange rate** per USD00 is set to 0.9236€
- Many factors were considered to be common for the expected service of the pipelines in the Model, such as materials, basic engineering definition, etc.
- The offshore cost equations are based on current "S-type" pipelay technology. This pipelay method is typically limited to water depths of 600-800 m.

Pipeline Operation and Maintenance costs were assessed as 2.6% of the capital cost.

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Abstract

Enhanced oil recovery using carbon dioxide (CO_2-EOR) is a method that can increase oil production beyond what is typically achievable using conventional recovery methods by injecting, and hence storing, carbon dioxide (CO_2) in the oil reservoir. At present there are no applications of CO_2-EOR in Europe, although the technique has been commercialised elsewhere. Major barriers include the availability of low cost CO_2 and the high capital and operating costs. This report indicates that the maximum technical potential for increased oil recovery is significant, a significant fraction of the existing reserves. On the other hand, the CO_2 storage capacity is relatively small, when compared to the level of the GHG emissions in the EU. A detailed economic analysis suggests that at the oil prices of today and with a financial incentive for CO_2 storage, a number of CO_2-EOR operations could be viable in the North Sea. These projects can contribute to the improvement of the European security of supply by increasing indigenous oil production, and assist in the reduction of GHG emissions and catalyse the development of decarbonised energy conversion technologies by providing the means for safe and permanent storage of CO_2.

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