A CO2-Infrastructure for EOR in the North Sea (CENS): Macroeconomic Implications for Host Countries

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ABSTRACT

The CO2* for EOR in the North Sea (CENS) Project offers the host nations a unique opportunity for securing future energy supplies while developing sustainable solutions in response to the challenge of climate change and compliance with their Kyoto commitments. The Project comprises a CO2-pipeline infrastructure in the North Sea capable of transporting more than 30 million tonnes CO2 per year (mtCO2/yr). The CO2 will initially be captured from on-shore coal-fired power plants in the UK and Denmark, and used commercially for Enhanced Oil Recovery (EOR) in the maturing oil reservoirs in the North Sea.

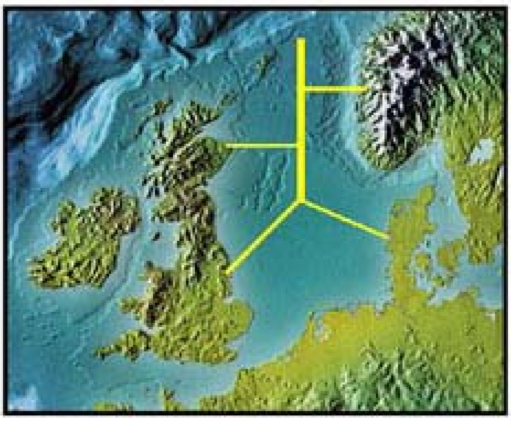

Fig. 1: *Sketch of the CENS concept superposed on a relief map of the North Sea basin.*

The scope of the CENS Project entails not only collaboration between the CO2-producers, transporters and users, but also the host countries. Only when these are active participants does the project reveal a 'win-win-win' situation for all stakeholders, including host governments.

The CENS Economic Models (CEM) shows that during a 25-year "economic" lifetime, the project could produce 2,1 billion barrels of incremental oil obtained while sequestering 680 mtCO2 in recognised secure depositories. Assuming price of oil at $20 /bbl then the net cost for CO2-capture and sequestration is less than $1,50 per tonne—this represents one of the

* We consistently use CO2 as opposed to CO_2 for denoting carbon dioxide.

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cheapest options available to the host nations for CO2-emission reductions. We do not for the time being attribute any value to the CO2-credits that may also be generated within the project.

In this paper we briefly elaborate on some of the macroeconomic benefits that the project can produce, including increased tax income, energy security, improved oil recovery, technology development, reduced CO2-emissions, capital investment and jobs. We also indirectly infer some longer-term benefits of a CO2-infrastructure whereby Northern Europe may be in a position to decarbonise existing CO2-emissions during the next half century using ageing oil and gas reservoirs.

Furthermore we perceive an accelerated commercial route towards a "hydrogen economy"—initially based on decarbonisation of fossil fuels [1] that can be supplemented by new-renewable hydrogen production, as these become commercially developed.

INTRODUCTION

The CENS Project is essentially a 25-year project for enhanced oil recovery (EOR). It is made possible by the maturing state of the oil reservoirs on the UK and Norwegian sectors of the North Sea Continental Shelf (NSCS). In Fig. 2 comparison is made with the similar situation that occurred in the US in the early 1980's. This stimulated the introduction of CO2 for EOR, particularly in West Texas where there now exists a 1500 km CO2-pipeline infrastructure transporting 22 mtCO2/yr—the majority of which is obtained from naturally occurring geologic formations.

The Houston-based *Kinder Morgan CO2 Company* (KMCO2) is the major operator of the Texas-pipeline infrastructure. In addition KMCO2 owns and operates the SACROC oilfield, West Texas, which is currently the world's largest CO2-flood.

The potential use of CO2 for EOR in the North Sea region is also made possible by a growing concern regarding CO2-emissions from coal-fired power plants in Denmark and the UK. These plants have a relative close proximity to the NSCS and represent the cheapest 'end-of-pipe' CO2 available to the oil field operators in a sufficient volume to warrant full-scale use of CO2 for tertiary oil recovery. It is also recognised that there are many additional sources around the North Sea rim that can in the future supplement this initial 'base volume' of CO2-supply [2].

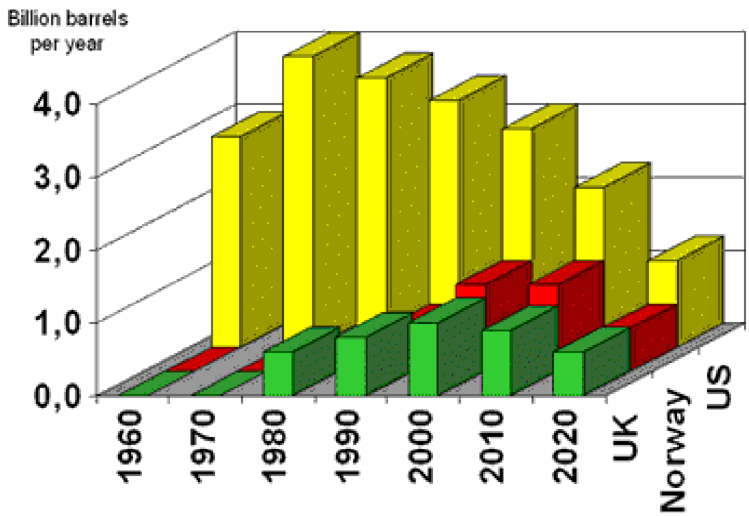

Fig. 2: *Comparison between US and North Sea oil production (1960 – 2020). The NSCS is currently moving into decline in a similar manner that occurred in the US in the early 1980's.*

Furthermore the commercial use of CO2 captured from coal combustion is appealing due to the recognised dominance that coal has within energy production. Inevitably, on the global arena, this will probably remain the case despite the move towards lower carbon content fuels (i.e. natural gas) in many of the industrialised economies. It is the detrimental impact of coal on the environment that is of major concern [3]. The potential for removing CO2-emissions commercially from existing coal plants using post-combustion decarbonisation should possibly strengthen the perceived global role for coal in a 'carbon constrained' global economy during the next half-century.

The longer-term implications of CENS suggests that the project may also be seen as an opportunity to straddle the gap between an existing high carbon fossil-based economy through to a sustainable renewable energy economy via decarbonisation, hydrogen-rich syngas and carbon sequestration. Within this perspective CENS could be a fundamental building block for commercially developing the necessary technology for economic and sustainable energy in the future.

OVERVIEW OF THE CENS ECONOMIC MODEL

The CENS Project primarily comprises four projects that cover: (i) power plant CO2-capture, (ii) CO2-transportation, (iii) CO2-injection for EOR, and (iv) CO2-stripping and recycling. Within the CENS Economic Model (CEM) each one of these are subsequently broken into sub-projects having specific capital investments, operational costs, revenue streams, capital charges, etc. The CEM contains nearly 50 inter-linked data sheets covering all the economic components of the project, together with summary sheets for specific sectors and host nations. Many of these sheets also incorporate macroeconomic aspects such as jobs created, technology development, taxation revenue, and other societal benefits that are not directly relevant to the project microeconomics. We can also make comparison with the 'No-CENS' case based on forecast production profiles and decommissioning costs for specific fields if the project does not occur.

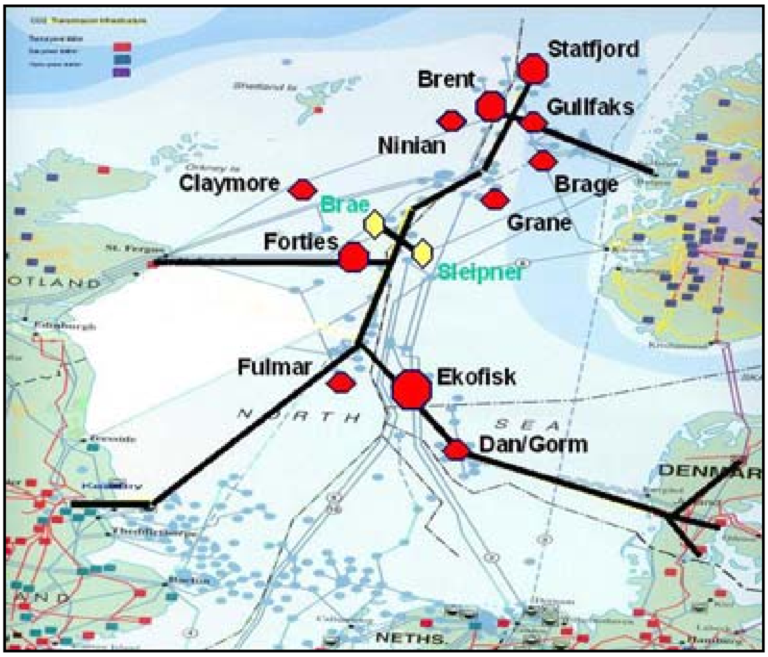

Fig. 3: Overview of possible CO2-pipeline infrastructure together with a portfolio of mature oil reservoirs that are representative candidates for CO2-flooding. Note that Sleipner and Brae are additional sources of CO2 having a comparatively high percentage as associated gas (equivalent to 1 – 2 mtCO2/yr respectively).

The essence of CENS is as a multi-discipline project with stakeholders from several separate sectors—all must see a satisfactory internal rate of return in order to individually move forward and invest capital. Our fiscal and macroeconomic modelling shows that a 'win-win-win' situation occurs for all stakeholders only when the host governments also become active stakeholders and project facilitators.

An overview of the project concept is shown in Fig.3. The designated fields are chosen as suitable candidates for CO2-flooding based on their existing production profiles and original oil in place (OOIP). They should be viewed as representative of a general portfolio of potential fields for the period 2006 – 2012[†].

The main components of the project, as currently envisaged, comprises an onshore pipeline infrastructure in Denmark (sketched) and UK (not shown), together with two main (24-inch diameter) feeder lines joining a southern hub near *Fulmar* and *Ekofisk*. The main 'backbone' is a 30-inch diameter pipe transporting the CO2 north to the fields in the *Tampen* area off the West Coast of Norway.

There is also some scope for connecting industrial and power complexes in Scotland with an additional feed line from St. Fergus via possibly fields like *Forties* or *Claymore*. These are representative of reservoirs in the more mature part of the North Sea requiring CO2 at the earliest possible opportunity starting 2006 – 8.

The feed line from the west of Norway to *Tampen* is primarily motivated by Norway's unique position as a major oil and natural gas (NG) exporter[‡]. By 2005 it is anticipated that total production of NG from the Norwegian sector of the North Sea will be around 140 bcm. However, the annual domestic consumption is presently less than 4 bcm. For this reason there is a strong desire to use gas onshore, combined with a need for decarbonisation in order to comply with Norway's Kyoto commitment. It is already well recognised that Norway is currently a major promoter for developing "zero-emission" power plant technology [4].

CO2-Capture

The Danish company *Elsam A/S* own and operate five major coal-fired power plants in Denmark with total installed capacity of 2,5 GW producing a maximum of 15 mtCO2/yr. During the past year they have conducted extensive investigations with major technology suppliers for installation of standalone post-combustion CO2-capture in conjunction with these power plants. The on-going work has

Capturing 90% of the CO2 emitted from Elsam's coal-fired power plants is commercially competitive because:

- **Ultra clean flue-gas with FGD and SCR are already installed.**
- **The flue-gas concentration is 12 - 14% CO2, which is three times the concentration for Natural Gas power plants.**
- **Steam at 290 bar / 580 °C minimises efficiency drop in conjunction with integration of amine capture technology.**
- **Integration with district heating also helps reduce loss in overall plant efficiency.**
- **Close proximity to North Sea CO2-Infrastructure.**
- **Potential production of between 10 - 15 million tonnes CO2 per year from 5 plants.**

[†] More recent work has also revealed clusters of smaller 'non-commercial' fields that also may be favourably disposed to CO2-flooding. The optimal economics of these fields is currently being investigated.

[‡] In 2001 Norway was responsible for exporting 4.2% of global oil consumed. At the same time it is also developing natural gas reserves equivalent to one-quarter of total European reserves. Annual export of natural gas to the European market was in 2001 around 57 billion cubic metres (bcm)—about 12% of total European gas consumption—but this is expected to reach 80 bcm by 2005. An additional 50 bcm of hydrocarbon (HC) gas is currently used for enhanced oil recovery (EOR), and it is uncertain regarding how much of this gas will be economically retrievable towards the end of the oil fields operational life.

provided detailed cost breakdown and identified improvements for better energy efficiency and cost reductions compared with earlier published studies. The CAPEX for a standalone capture plant varies from US$ 140 – 195 million with size range 400 – 800 MW. Power plant load factor depends on the local co-generation configuration but will typically vary from 70 – 90%.

The CEM also includes 18 potential coal-fired power units in the UK, but currently only four of these (yielding 16 mtCO2/yr) are part of the present economic analysis. The UK plants have been chosen because of their location near the coast, and that they have a similar cost potential as their Danish counterparts. However, overall the exact cost of capture will depend upon final project configuration, volume of CO2 demand, and the rate at which the CO2-offtakers come on-line in the period 2006 – 12.

CO2-Transportation

KMCO2 have with *INTEC Engineering BV* conducted extensive studies regarding pipeline routing, size and power requirements. The scenario shown in Fig.3 comprises 1500 km of CO2-pipelines offshore together with 900 km onshore in Denmark and the UK. The total transportation investment cost is estimated to be $1,69 billion. However again, the detailed extent of the pipeline economics can only be determined once the suppliers and off-takers have confirmed volumes to be transported, and dates for delivery of initial gas.

Despite this uncertainty the CEM does provide a capability to analyse different scenarios for a North Sea infrastructure, thereby yielding an envelope of values for capture and transportation costs. To date our scenario analysis suggests that the 'end-of-pipe' cost for delivered CO2 will be in the range of $32 - $35 per tonne. Elsam and KMCO2 are currently comfortable with confirming that $35 /tCO2 is sufficient for both of them to make a commercial investment decision for first delivery of CO2 to the oil field operators in 2006.

CO2-Injection for Enhanced Oil Recovery

CO2 for EOR will require major investments to the oil platforms and oil reservoirs. However there already exists considerable onshore experience from the Permian Basin, West Texas regarding reservoir response and corrosion mitigation. Furthermore the handling and injection of CO2 offshore is well established practice (see Figs. 4 and 5).

Offshore CAPEX will be platform and field dependent, thus difficult to predict with any certainty before focusing on specific installations together with the operator. In this area the CEM is conservative in its assumptions. We model a total offshore investment of nearly $5 billion spread over 12 fields. We believe this is a substantial investment covering what will be needed for topside modifications and 'down hole' corrosion protection before a platform may initiate a CO2-flood. We also note that the project economics is reasonably robust to allow for an offshore investment of $6 billion if necessary.

Fig. 4: *The Sleipner-T (CO2 amine-treatment) and Sleipner-A (production) platforms, where one mtCO2/yr are currently treated and injected by Statoil as part of a pilot study on saline aquifer storage in the North Sea.*

Furthermore we assume that only 6% of the original oil in place (OOIP) will be recovered. Experience has shown that the actual value will often vary in the range from 6 – 15%. Although the true value of the CO2 in the reservoir can only be estimated with detailed compositional modelling, experience shows that it is optimised through careful monitoring of reservoir response during the CO2-flood process. We assume that 6,000 cubic feet of CO2 is necessary to produce one barrel, this being equivalent to 3,1 bbl/tCO2-injected. This is also recognised as being a conservative estimate.

Decommissioning costs ($150 million per platform) are deferred to allow for extended field operations. In both the UK and Norwegian sectors much of these costs are to be carried by the respective governments. The model also includes possibility for variation in the taxation regimes by each host government, including royalty, petroleum revenue tax (PRT) and corporation tax. Furthermore the rules governing depreciation of invested capital can be modified in the model.

CO2-Stripping and Recycling

A main feature of existing onshore CO2-floods is that following initial CO2 injection there is typically a 9 – 18 month response time before increased oil production. For offshore fields, with sparser injector and producer well spacing, this response may be 18 – 36 months. The model assumes two years (and tests sensitivity of field IRR using one and three years). Subsequently as the EOR phase evolves there is a need for stripping CO2 from the produced crude and re-injection. As illustrated in Fig. 5 such technology is already adapted for offshore applications. The incremental cost of handling CO2-enriched crude, stripping, drying and re-injection into the reservoir is estimated in the model as $1,5 /bbl.

Figure 5: *A CO2-membrane stripping unit (high-lighted) attached to an offshore platform operated by Unocal in the Gulf of Thailand. The unit shown here is handling 1,8 mtCO2/yr.*

PROJECT ECONOMICS

The CENS Project requires integration of sub-projects within three main industry sectors: (i) power plant CO2-capture, (ii) CO2-transportation, and (iii) CO2-injection for EOR (with CO2-recycling). For comparison purposes we average the IRR and NPV of each sub-projects so as to provide an initial indication regarding how the three sectors will perform. We weight the averaging with respect to the capital investment of each sub-project. All net present values (NPV's) used are assuming an 18% discount rate for oil field operators, 15% for the pipeline operators, 12% for power plant owners, and 7% for the governments. These differences respect—to a certain extent—the real expectation for the return on capital invested in the different sectors.

In the CEM we can also look at modifications in the tax structures while comparing pre- and post-tax project economics, as well as IRR between a full equity and a loan-financed project (assuming 6% interest rate). We maintain that the price of coal is $1,50 /GJ, the cost of electricity is $25 /MWh, and oil is at $20 /bbl. Comparisons presented in this paper are assuming a 40% debt-financed project.

Using the above we find that an 'end-of-pipe' delivery sale price for CO2 of $35 per tonne will satisfy investment hurdle-rates that are typical in sectors (i) and (ii). However the economic model also shows that the offshore EOR projects will need an oil price of $29,37 /bbl to satisfy typical investment requirements in sector (iii).

Alternatively with oil at $20 /bbl then the necessary CO2 sale price to the oil field operators would be $12,07 /tCO2. This is a level that is not sustainable for projects in sector (i) and (ii). We have currently attributed no value to the potential CO2-credits that may eventually be generated and distributed among the project stakeholders. However it is also evident that the shortfall in price of $22,93 is not a realistic credit value that the emerging emission-trading market would currently support, and therefore does not provide any basis for making an investment decision for a project in the 2006 – 2012 time frame.

MAKING CENS FOR THE HOST NATIONS

Ultimately it is the host nations that perceive a net benefit through participating in the CENS project. The economic model indicates that with the current tax structure these governments will obtain an incremental $5,79 billion in fiscal revenue by way of direct petroleum-, corporation- and income taxation. At the same time a CO2-support price of $22,93 /tCO2 is equivalent to an expenditure of $6,77 billion. The net deficit of $0,98 billion is the (discounted) cost these governments need to pay in order to remove 680 mtCO2-emissions from the atmosphere at a price equivalent to $1,44 /tCO2 over the 25-year duration of the project.

The CEM also shows that if the oil price rises above $21,18 /bbl then the host nations become net beneficiaries of the project. (If the offshore capital investment increases from $5 to $6 billion then the price of oil would need to rise above $22,21 /bbl before host nations became net beneficiaries.)

Alternatively if we maintain oil at $20 /bbl, but assume that a credit trading value of $5 /tCO2 is available to the project participants, (with this being distributed internally one-third to each sector). Then the credit value will reduce the required CO2-sales price from $35 to $33,24 /tCO2, and ensure a net government surplus of $0,71 billion. This is equivalent to a positive income of $1,04 /tCO2-captured. Increasing the CO2-credit to $10 /tCO2 leads to a government surplus of $2,41 billion and a positive income of $3,53 /tCO2-captured.

The preliminary calculations using the economic model also indicates that there is little incentive for host governments to reduce their *Special Tax* (in Norway at 50%) and *PRT* (in UK at 50%), as this decreases their petroleum income and net benefit. However on the Norwegian side we observe that modifying the linear depreciation for capital investment from six to three years does have a marked favourable influence on IRR of the Norwegian EOR projects.

CONCLUSIONS

The CENS Economic Model (CEM) is still at an early stage of development, and we have in this paper simply wanted to indicate a few examples of approximate costs, benefits and sensitivities. To date we have made every effort to remain conservative in our assumptions by including the reality of our different business environments. The most crucial part of the model that still needs to be better elaborated upon concerns the offshore capital investment, and the final 'value' of the CO2 in the reservoir. This work is in progress with the oil field operators.

Furthermore there are numerous 'what-if' scenarios that can be considered using the CEM. We believe that the model may also become a useful tool to help host governments assess possible strategies for CO2-emission reductions and identifying incentives to further the use of CO2 for EOR in the North Sea.

ACKNOWLEDGMENTS

The CENS Project has evolved in close dialogue between the project developers (Elsam / KMCO2), technology providers, oil companies, and power plant operators. Furthermore there has been considerable dialogue with governmental departments in the UK, Norway and Denmark. The Project would therefore like to thank all those that have provided valuable information and support, including specifically the *Norwegian Petroleum Directorate (NPD), Danish Energy Agency (ENS), UK-TradePartners, Department of Trade and Industry (DTI),* and many individuals who have helped promote the project in a constructive manner—thank you!

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