

A LOGISTIC AND ECONOMIC PERSPECTIVE ON DELIVERING CO₂ FOR EOR PROJECTS IN THE NORTH SEA

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Abstract

Logistics cover all aspects of planning, implementing and executing projects, as well as applying to much of the “behind-the-scenes” activity that tie together component parts creating complete value chains. In this paper we specifically discuss logistic in the context of using carbon dioxide (CO₂) for enhanced oil recovery (EOR) in the maturing oil reservoirs of the North Sea. Here, history, experience, relationships, similarities and contrasts will all assist in facilitating CO₂-EOR projects. However economics—and stakeholders—will finally determine whether or not such projects can ultimately be successful.

In this, and a companion paper discussing the CO₂ value chain [1], we emphasize how equitable fiscal modifications are probably needed to encourage and assist commercial stakeholders facing large capital outlay and high CO₂ operating costs incurred during the early project years on the North Sea Continental Shelf (NSCS). Subsequently, once established, we see an opportunity for a self-sustaining CO₂ commodity arena that may also contribute to the issues of energy security and diversification of energy supplies for Europe, in combination with enabling cost-effective measures for CO₂-mitigation within the host countries.

Introduction

The logistics of delivering CO₂ for EOR projects not only covers how CO₂ is produced, transported and used by field operators for the final (tertiary) production phase of reservoir life. But also includes additional activities such as handling, interim storage, compression, injection, recycling, etc. However, contracts, negotiations, purchasing, cash management and engineering expertise are all examples of logistical “back office” involvement needed to ensure that the physical CO₂ can be integrated into a commodity that creates a CO₂ value chain and enables successful CO₂-flooding. Furthermore, there will be a certain combination of events and conditions that ultimately determines if, how and when such a tertiary era may materialize in the North Sea.

The Market Price for Crude Oil

For all EOR projects the most important parameter is the future market price of crude oil. Since the 1980s this has essentially moved up and down around a \$20 /bbl reverting mean price. However, for the past three years crude prices have ranged between \$25 - \$42 /bbl (with Natural Gas prices during the same period varying between \$4 - \$10 /mcf, see footnote¹). Petroleum products are currently selling at all time high worldwide. While such price levels have been seen before (most notably after the 1979 Iranian revolution, when U.S. price controls also exacerbated the situation; and in the run up to the first Gulf war), high prices for prolonged periods were not sustainable.

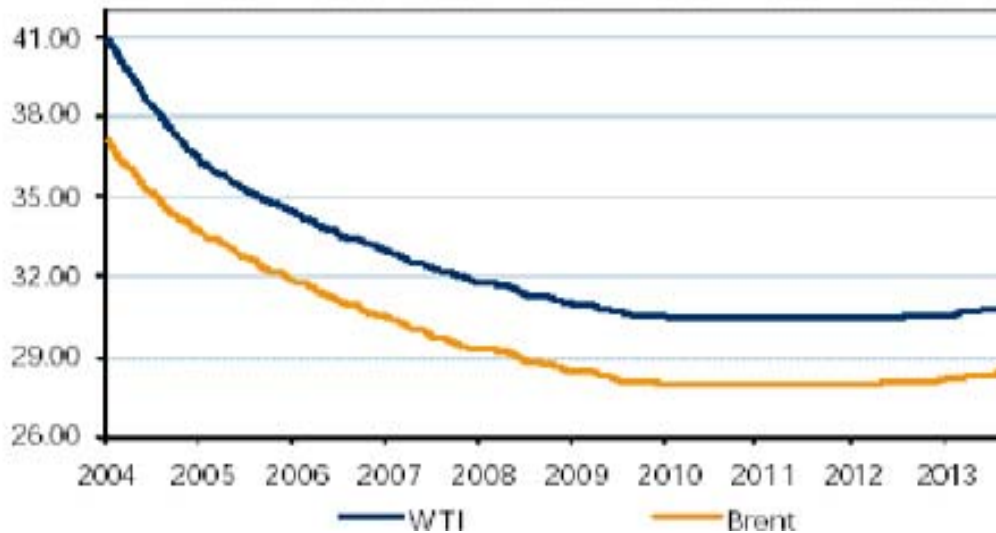
¹ Crude oil price is cited in US\$ per barrel (bbl), and is measured in barrels per day (b/d) or thousands of barrels per day (Mb/d). Natural Gas (NG) is cited in US\$ per thousand cubic feet (mcf) and is measured as mcf per day (mcf/d), millions of cubic feet (MMcf) or MMcf per day (MMcf/d). In SI Units we denote crude oil and natural gas in volumes of cubic meters (m³). There are 28.3 m³ per mcf and 6.29 barrel per m³. CO₂ is sold in the same denominations as NG in the U.S. and in this paper will alternatively be described in metric tonnes (t), and millions of tonnes per year (mtCO₂/yr).

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Likewise, there have been periods with crude oil prices at the opposite end of the spectrum; most notably 1986 - 1988 and 1997 - 1998. However, there is a growing acceptance that prices will not return to the \$20 /bbl and \$2.50 /mcf² reverting mean of the last three decades—primarily because the world has evolved, and cannot change back. Using the metaphor of eyesight, we are older. Our petroleum eyes have changed in small, additive and imperceptible ways that only now have become large enough to be noticeable and effect our lives. We must wear crude-oil and natural-gas bifocals from now on (which of course, are more expensive!). The industry will therefore never be young again.

There is still plenty of oil remaining to bring to market—it is just going to be more expensive. As shown in Fig.1 the finance sector (and energy publications) are predicting 2005 - 7 forward curves to lie conservatively above \$30 /bbl with NG (not shown) around \$5 /mcf. Furthermore the longer-term 10-year curve is close to \$30 /bbl.

Fig.1: Ten Year Forward Price Curve for Market Crude Oil (West Texas and Brent)³.



However, possibly the fundamental reason for sustained higher average oil prices is the effect of world wide population growth. In 1980 the world population was 4.5 billion, whilst 23 years later it is now an estimated 6.1 billion. It took only 12 years to grow from 5 to 6 billion in the period 1987 - 1999 [2].

Whilst exploration and technology has continuously assisted in helping keep up with ever increasing demand, petroleum resources are finite, and supply is being outstripped by demand. Despite oil company focus having expanded, and with smaller fields being developed, the older and larger fields are depleting. Thus in a world with increasing demand, pulled by ever increasing population growth, price can do nothing in the medium to long term, but increase.

Market Drivers for CO2-EOR Investment

What, if anything, can the industry do to counter these developments? The answer in many cases would appear to be tertiary CO2-flooding, and thereby recover approximately 30% additional remaining reserves in existing reservoirs that would otherwise be left behind when traditional secondary water-flooding becomes uneconomic [3].

² Prices for natural gas have never been higher and should significant numbers of new LNG re-gasification capacity be constructed, a virtual floor for gas will be established near or above the \$4 /mcf level.

³ Based upon Barclays Bank, NYMEX Futures, IPE Brent Futures and Derivative Market, July 20, 2004. These forward curves also have banks seriously looking into financing longer term CO2-EOR floods, required capture and technology development costs, infrastructure development, and the emerging Emission Reduction Credit markets. (Source: M. Moore, Falcon Environmental Services, Houston, Tx.)

Carbon dioxide can move the peak oil supply curve a little into the future and allow mature oil provinces such as the NSCS to remain productive for possibly decades to come. However there are several other issues that may well keep North Sea operators from taking the decision to use CO₂ for EOR. These are; (i) prices and costs, (ii) extended negative cash flow, (iii) lack of expertise, (iv) technology transfer requirements, (v) security of supply, and (vi) proper fiscal support combined with encouragement from host governments. We discuss each of these in further detail below.

(i) Price v's Cost: The perceived future commodity price an Oil & Gas operator believes he will receive for projects being contemplated today is what drives economics in the petroleum industry. Companies having productive CO₂-floods, and with an oil price of \$40 /bbl, are presently ecstatic; and most might argue they should move ahead at breakneck speed to use as much CO₂ as possible, to recover as much oil as possible, in as many projects as possible, as quickly as possible! Right? Wrong!

CO₂-EOR projects fall into two seemingly “contradictory” states:

- (I) The first is self-explanatory; earnings in the current market (for each barrel produced) are very good, and much better than contemplated.
- (II) The second is harder to see; CO₂-floods need higher prices to be economical—it *really* does cost more to try to recover that last one-third of the remaining oil.

Here is the contradiction; no production company enjoying extraordinary earnings in the current market, will model the higher oil prices into its future project scenarios. Nor will many—if any—take steps to sell forward future potential CO₂-incremental barrels to mitigate the very expensive up-front costs needed to make a CO₂-flood successful.

For all producing CO₂-floods, the current high oil price is exceptional and fortunate. Rates of return for projects are greater than predicted when these were just projects in the planning phase. However, future CO₂-EOR projects now in the formative phase, simply are not viewed in the similar light of high prices because the *price premise* adopted also determines the amount of risk a company is willing to assume—and no company will use the current prices to model future projects!

So despite crude prices at their all time high and there being no real rationale for a large correction back to former average levels of \$18 – \$20 /bbl, companies operating in the North Sea have until recently been calculating with crude oil as low as \$14 /bbl. Although with recent market developments they have raised this to lie between \$17.50 – \$20 /bbl, depending on the company. In contrast most oil companies in the U.S. are currently modeling EOR projects using a \$22 – \$25 /bbl future price assumption [4]. Why is it that oil companies in the North Sea have such a pessimistic forecast for market crude oil price? Some of the answer obviously lies in risk assessment.

In the NPV models used by oil companies price is the most important variable. The point along the time line where CO₂-incremental barrels begin to generate revenue, to offset large up-front capital costs, determines the magnitude of project IRR forecasts. This, coupled with the unknown oil price creates considerable uncertainty for a CO₂-flood.

Costs are the “anti-price”, however these are seen to be more manageable because an oil company has some control to negotiate them, and changing cost structure is not considered to be as volatile.

(ii) Extended negative cash flow & Delayed response: The incremental capital and operating cost required to implement a CO₂-flood in the U.S. Permian Basin averages about 10 - 15% more than a similar water-flood project (excluding the cost for CO₂ purchase). In the North Sea this may well be 20% (again not including cost of CO₂). On balance though, the increased capital and operating expenditure should not be too high to kill CO₂-EOR project economics.

However, hidden in the cost portion of CO₂ project expenditure is the total up-front expense of securing, supply and delivery of CO₂. This total cost must therefore also be absorbed until incremental production occurs. Applying

the rule of thumb that one incremental barrel of oil is produced using 6 mcf of CO₂, then the economics can become challenging. Add to this the response timing issue⁴ and the IRR for a CO₂-flood can be significantly affected.

(iii) Expertise & Experience: During the course of developing the CO₂ project it is also essential to readily be able to handle many of the issues that are listed below:

- Pipeline to injector wells and lease line re-deployment.
- Additional wells / modifications for injectors or producers.
- Modified tank batteries for separation and recovered CO₂ handling.
- Additional pumps and compression to inject CO₂ into the formation.
- Laying of CO₂ pipeline in the field.
- Managing costs associated with CO₂ separation once breakthrough occurs

In the North Sea there will inevitably be a notable 'CO₂-expertise' factor that is lacking within many of the established operators⁵. Furthermore there will be increased labor cost (to monitor and work the field), as well as incremental power requirements combined with limited space available for refurbishing existing platforms. These are therefore all additional considerations that must be included with the up-front CO₂ costs for the project.

Finally, it is not just knowledge and experience that counts, it is also having *done it before*. Knowing for example: the proper type of pipe to lay; how to mitigate any potential corrosion effects; special metallurgy needs and down-hole expertise when dealing with CO₂ in a corrosive environment; what CO₂ / HC gas separation technology to apply; how to monitor and measure; which SCADA system to use, and having the reservoir engineering skills to be confident about accurately calculating and modeling why and where to put the CO₂ into the formation whilst predicting when and how to maximize recovery. Furthermore, a company must have geologists and engineers with expertise and experience to implement CO₂-floods offshore in the North Sea environment. With no culture around CO₂-EOR because no CO₂ has ever been available, one can begin to understand why there may be some reluctance from companies and top management to initiate CO₂-floods on the NSCS!

In the U.S. Permian Basin, there has been and continues to be significant 'hands on' expertise. However here too, since the mid 1980s, there have been retirements, layoffs, mergers, acquisitions, price crashes and rationalization. In short, time has passed and much of the earlier CO₂ expertise has either moved on or become concentrated in only a few major oil companies. Therefore for most companies taking that next step offshore into the North Sea is daunting. And it is only recently that commercial companies have spent considerable sums of money to evaluate large-scale infrastructures for CO₂ [5] and the first potential delivery to CO₂-floods [6].

(iv) Technology Transfer: The technology for transporting and using CO₂ is proven onshore from the Permian Basin, West Texas [7]. Oil companies can therefore adapt available onshore technology to an offshore environment. They can find the correct CO₂ compressors; implement proper down-hole corrosion techniques needed to minimize the effects of CO₂ in water under high pressure; determine the best options to separate CO₂ from hydrocarbon gas and recycle the gas into the reservoir. All this can therefore be achieved for the harsher environment of the North Sea using established expertise that is available within several of the major oil companies.

The two most challenging issues will be ensuring that the reservoir engineering is accurate for the North Sea geology so that CO₂-flooding will be as successful as possible, and confirming that the supply of CO₂ will be there when needed throughout the lifetime of the project.

⁴ Once a field is ready to receive CO₂ and flooding begins, depending on the geology, the CO₂ injected may not cause the production of additional oil for as long as eighteen months. This means that if the project needs 100 MMcf/d (approx. 1.9 mtCO₂/yr and) and each Mcf costs the operator \$0.75 (\$14.25 /tCO₂), then the cost incurred, for CO₂ alone, before recovery of the first barrel of CO₂-incremental oil, can be as high as \$40 million.

⁵ This is not a competency issue, but instead a lack of 'hands-on' experience that has developed as a consequence of the historical evolution in the region with focus on either water-flooding and / or use of readily available hydrocarbon gas for WAG.

(v) Security of Supply and CO2 Aggregation: In the Permian Basin, there are approximately 15 trillion cubic feet of CO2 available for EOR projects. This secure CO2 availability is already established through a large pipeline infrastructure, with a history of timely delivery for projects spanning two decades [3,7]. Security of supply issues were originally resolved whereby the majority of projects in the 1980s and 1990s were commissioned under the model that the cheapest CO2 was equity CO2—one's own CO2 was the most cost-effective way to reduce risk.

In the North Sea there is no 'cheap' CO2, no infrastructure, and it is clear that no major CO2-flooding will start until a secure source can be guaranteed. Oil companies will therefore probably need to rely on sources of CO2 over which they have no control save contractual ties. Off-takers will demand ironclad contracts with their anthropogenic CO2-suppliers. The parties will be linked not only physically, but also through trading and aggregation mechanisms that do not yet exist. Commercial agreements will need to be written tying both parties together for a long term with operators demanding high, tight 'deliver or pay' requirements combined with liquidated damages for failure to perform. No doubt suppliers will seek similar considerations from their own perspective.

Invariably some kind of aggregator will presumably play an important role because neither the field operator nor the CO2-supplier have production and maintenance schedules that compliment each other.

(vi) EOR and the Tax Regime: In the United States tertiary projects of all kinds have for more than two decades been given fiscal incentives in one form or another. In the early 1970s, before Alaska production and prior to the original oil embargo, Texas was the largest oil producing State. During that era each well had an allowable production volume; once the permitted volume had been produced, the well was shut in until the next period. Tertiary projects however, received exemptions thereby encouraging EOR and enabling the field to produce more oil.

Later in the 1970s, during crude oil price controls, reservoirs that used EOR techniques were allowed to sell the *tertiary incentive oil* as market priced oil rather than retain its original "tier" classification of either old oil or upper tier oil. Especially from 1979 to de-control in 1981, this re-certification amounted to well over \$10 /bbl.

With the introduction of the *Windfall Profits Tax* in 1981, oil attributable to tertiary projects was taxed at a lower rate. Lastly, from the federal perspective, Section 43(c) 2(A) of the IRS code allowed tertiary producers a 15% federal tax credits to apply against the company's tax burden. Several States also gave tertiary production allowances. Texas the largest, allowed severance taxes to be either eliminated or substantially reduced. In total seven states, not surprisingly the largest oil and gas producing states, all gave and continue to give allowances for producers willing to take on the extra cost for EOR. The federal tax credit is also still in place as well [8].

Equitable Fiscal Changes

In order to address some of the challenges raised in the previous section there are two paths that may be explored. First, is the ability to transfer some CO2-EOR risk into the commodity markets and using the longer-term forward price curves for oil, as shown in Fig.1, where EOR crude oil has the ability to be swapped far into the future. If the correct ratio of future crude to CO2 contract volumes is agreed with proper delivery assurances. Then it is possible to effectively handle some uncertainty regarding project IRR so that the significant up-front costs for CO2 purchase could be mitigated.

Secondly, there is the consideration regarding what price can or should be charged for CO2. In the CENS study [9] it was determined that CO2 could be delivered for \$35 /tCO2 and sufficient CO2 could be aggregated to initiate a wider portfolio of CO2-EOR projects. In such as scenario, it was also determined that the minimum price for oil produced to allow an adequate rate of return was ~\$28 /bbl. Furthermore if the host governments were to work with the oil companies to offer, not a subsidy, but a sliding-scale backstop beginning at \$28 /bbl, then this too would mitigate the risk of lower crude price to the producer who has to purchase anthropogenic CO2 at a cost far above that in the Permian Basin (from an infrastructure that does not yet exist!).

Conclusion

There are many challenges to bringing CO2-EOR onto the NSCS. However, none are insurmountable for the North Sea operators if discussed in dialogue with host governments. In this discussion paper we have emphasized how logistics is important for continued development and implementation. Specifically what is still lacking is much of the pre-requisite logistics that enables a way forward. These include;

- (i) Fiscal policy to establish ground rules for bringing new life to old oil fields that clearly will be abandoned or their lives shortened prematurely, leaving potentially billions of barrels of oil in the ground.
- (ii) Establishing a government sliding-scale backstop (or price guarantee), that need only be implemented under certain circumstances.
- (iii) Encouraging oil companies to work with financial institutions to creatively implement financial strategies that mitigate the up-front costs for CO₂-EOR projects.

What has not been accomplished to date is any formal recognition that assistance may be needed to entice the operators on the NSCS to take additional risk and begin large-scale implementation of CO₂-EOR. There does not appear to be any concerted effort between stakeholders and governments to negotiate an equitable way forward. So that the ability to produce future EOR barrels lies very much in the balance. At the same time the longer-term benefits with regards to substantial sequestration of CO₂-emissions will also not be realised [1].

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It must be stated here that this paper has no intention of establishing priorities for the governments or the oil companies, but merely to illuminate certain options that are available to possibly enable more rapid investment and implementation of CO₂-EOR projects in the North Sea.

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