Storing CO_2 through Enhanced Oil Recovery

Combining EOR with CO_2 storage (EOR+) for profit

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Executive summary

Injecting carbon dioxide (CO_2) into oil reservoirs to enhance oil recovery (EOR) has been commercially used for several decades in the petroleum sector. As the increasing pressure to combat climate change has brought carbon capture and storage (CCS) to the forefront as an emissions mitigation tool, greater attention is being paid to the potential for CO_2-EOR to support geological CO_2 storage for climate change mitigation.

Novel ways of conducting CO_2-EOR could help achieve a win-win solution for business and for climate change mitigation goals, offering commercial opportunities for oil producers while also ensuring permanent storage of large quantities of CO_2 underground. Transforming practices to support climate change carbon storage objectives in addition to oil extraction, i.e. moving from simple EOR to "*EOR+*", represents a potentially attractive and cost-effective way to spur greater CCS action.

CO_2-EOR practices can be modified to deliver significant capacity for long-term CO_2 storage. Extending EOR to qualify as CO_2 storage can be achieved through a minimum of four main activities: i) additional site characterisation and risk assessment to evaluate the storage capability of a site; ii) additional monitoring of vented and fugitive emissions; iii) additional subsurface monitoring; and iv) changes to field abandonment practices.

CO_2-EOR can be used for CO_2 storage in a manner that is economically interesting for industry. This analysis develops three distinct models combining oil extraction with CO_2 storage, which are useful to illustrate the technical and economic options:

- ***Conventional EOR+***: current CO_2-EOR practices, which aim to maximise oil production with a minimal amount of CO_2, are adjusted to provide for additional monitoring and verification practices designed to permit CO_2 storage tracking for mitigation purposes.

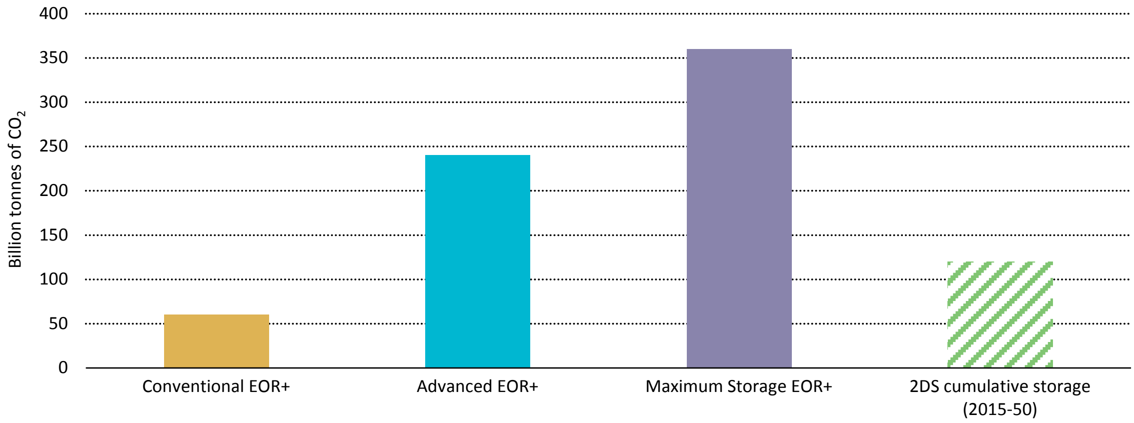
- ***Advanced EOR+***: a second option is to "co-exploit" two business activities, namely both (a) oil recovery and (b) CO_2 storage for profit. This approach involves the injection of larger amounts of CO_2 than under *Conventional EOR+*, as well as greater additional oil recovery.

- ***Maximum Storage EOR+***: CO_2-EOR operations are undertaken with a strong focus on maximising long-term storage of CO_2 in the oil reservoir while achieving the same level of oil production as under the *Advanced EOR+* scenario.

Analysis of a hypothetical, representative field clearly demonstrates that, in a carbon-constrained world, "co-exploiting" the storage of CO_2 with oil extraction to generate more profits using two different revenue streams is feasible. A key insight is that for the oil and carbon prices assumed in the 2-Degree Celsius (2 °C), 4-Degree Celsius (4 °C) and 6-Degree (6 °C) Scenarios (2DS, 4DS and 6DS respectively) modelled in the IEA publication, *Energy Technology Perspectives* (*ETP*), a CO_2-EOR practice that aims at co-exploiting both recovery and storage, i.e. *Advanced EOR +*, leads to net present values (NPVs) that are consistently larger than those achieved with *Conventional EOR+*. While the business case is ultimately project-specific, the hypothetical case provides valuable insights.

At an aggregate global level, estimates indicate that by 2050, a cumulative 60 gigatonnes of CO_2 ($GtCO_2$) could be stored in declining oil reservoirs with *Conventional EOR+* practice, corresponding to half of the IEA 2DS requirements outlined in *ETP* (see Figure ES1 below; also Figure 8, p. 25 [to which it is identical]). With *Advanced EOR+*, some 240 $GtCO_2$ could potentially be stored, exceeding the CO_2 storage requirements under the 2DS case. Storage potential under *Maximum Storage EOR+ is estimated at* 360 $GtCO_2$.

Figure ES1 • Global storage potential for different CO_2-EOR practices ($GtCO_2$)



While both the economic and CO_2 storage potential seem significant, adding these CO_2 storage practices to EOR (the "+" in *EOR+*) requires a clear paradigm shift from current practices. At present, no CO_2-EOR site is pursuing this dual objective: today EOR operations are carried out with the aim of maximising oil output with the minimum CO_2 input. Extending CO_2-EOR projects to include CO_2 storage as an end goal requires taking on activities associated with monitoring and verification of stored CO_2. The level of additional cost varies widely, depending on the geological and geophysical features of individual reservoirs

"Co-exploiting" CO_2 storage and EOR is unlikely to happen in the short to medium term without additional incentives, as applying novel practices increases cost and carries additional risk. Key to adding CO_2 storage to EOR activities is a carbon price or some regulatory mandate as in all cases, the storage for mitigation purposes will entail additional costs to conventional CO_2-EOR projects. Governments may need to step in by creating a policy framework comprising multiple and complementary economic instruments, of the type being used to stimulate CCS deployment more generally:

- *EOR+* pilot projects are needed to help to de-risk the technology and generate learning. In the longer term, increasing the capacity to extract oil needs to be tempered with policies that optimise CO_2 storage and ensures its environmental effectiveness. Early projects can also be beneficial for the creation of a CO_2 transport infrastructure.
- Specific incentives may be required to kick-start deployment. For example tax incentives could be considered. Carbon pricing could serve as an appropriate policy instrument at a more mature stage of technology deployment.
- A framework of laws and regulations is needed to ensure the safe and effective design and operation of CO_2 storage options. For CO_2 stored through *EOR+* to qualify as "not emitted" – and thus gain the benefits of climate policy – the operator must comply with regulations to ensure that the CO_2 is retained in the reservoir.

Introduction

Injecting CO_2 into oil reservoirs to enhance oil recovery (CO_2-EOR) has been practiced on a commercial scale for nearly 50 years. Most of this practice has been developed in North America. As increasing pressure to combat climate change has brought CCS to the forefront as an emissions mitigation tool, many have looked to CO_2-EOR as a means of supporting geological storage of CO_2 storage (IEA, 2015).

Four decades of CO_2-EOR experience have generated in-depth knowledge about technical aspects of the process and its economic benefits. Much has been learned about project design and reservoir management for CO_2-EOR, reducing the risk and costs associated with developing projects. Today, there is little doubt that CO_2-EOR can be a cost-effective way to prolong the lifetime of a conventional oil field, enabling the extraction of more of a valuable commodity wherever the right conditions exist. Improving recovery from existing fields can also reduce the pressure to develop new oilfields, thus avoiding the associated cost and environmental impacts, which can be an attractive factor for governments and companies. As a result, CO_2-EOR has turned CO_2 into a bulk commodity in North America placing a market value on its supply through extensive pipeline networks.

Yet a number of questions remain in relation to potential for CO_2-EOR to generate climate mitigation benefits resulting from CO_2 storage. While previous studies have largely focused on the potential for an expanded CO_2 supply to expand oil production via CO_2-EOR, and therefore store more CO_2 as part of the process, this IEA study takes a different perspective: it looks at the potential economic impact of modifying EOR at the project level to include storage of CO_2, and then quantifies the global potentials for CO_2 storage and additional oil production in aggregate.

The first chapter describes conventional CO_2-EOR operations, as undertaken today. The second chapter then describes how traditional CO_2-EOR practices, designed to maximise oil production with little attention to the ultimate disposition of CO_2, can be modified to provide verifiable CO_2 storage consistent with the requirements of climate change mitigation objectives. Projects that go beyond traditional CO_2-EOR practices to provide CO_2-storage are referred to as "*EOR+*" projects.

The second chapter then considers alternative cases in which *EOR+* practices are further modified to increase the amount of CO_2 stored, while continuing to support oil extraction operations. Three different levels of CO_2 storage activities are presented: (a) an initial level in which the storage is incidental to conventional EOR (*Conventional EOR+*); (b) a second level in which both the amounts of CO_2 stored and oil produced are increased above the conventional case, resulting in increased revenues from both CO_2 storage and oil production (*Advanced EOR+*); and (c) a third level at which the amount of CO_2 stored is increased substantially, consistent with the underlying oil production activities (*Maximum Storage EOR+*).

The third chapter analyses the potential magnitude of these sequestration actions through *EOR+* at a global level. A rich dataset of oilfields has been examined to assess the potential scale of CO_2 storage through *EOR+* operations at a global level if there were incentives for operators to increase the amount of CO_2 stored when producing oil. The fourth chapter considers the complicated question of the net impact of increasing CO_2 storage through *EOR+*, and lays out the conditions under which *EOR+* could raise oil demand at the margins while still providing a net reduction of emissions. The final chapter considers various issues that policymakers will need to address to realise the benefits of *EOR+* for climate change mitigation.

CO_2-EOR today: An oil production tool

Key points

CO_2-EOR is one of many technologies that can be used to enhance oil recovery. Today, the main concentration of CO_2-EOR projects is in North America, mostly in the Permian Basin of the United States. So far CO_2-EOR has been undertaken with the primary aim of enhancing oil recovery. Climate change mitigation and long-term CO_2 storage goals are not principal drivers for EOR projects.

Oil fields typically have various production phases. In the primary production phase, natural pressure drives oil to the production wells. In the secondary phase, pressure in the reservoir is increased by injecting fluids, pushing more oil to the production wells. In the tertiary phase, techniques are used not only to maintain pressure in the reservoir, but to also alter properties of the oil or reservoir, improving recovery of the existing oil.

CO_2-EOR is a tertiary technique, based on injection of CO_2 and usually, but not always, water into the oil reservoir. CO_2 mixes with oil, improving its ability to flow towards production wells. Injected CO_2 is produced with the oil; this CO_2 is separated from the oil and re-injected for further oil recovery.

Injecting CO_2 into oil reservoirs to enhance oil recovery has been practiced on a commercial scale for nearly 50 years, with the first successful pilot tests conducted in the early 1960s in the state of Texas (Holm, 1987). Experience in the United States shows that CO_2-EOR can boost recovery by 5% to 15% of the original oil in place (IEA, 2013b).

What is CO_2-EOR?

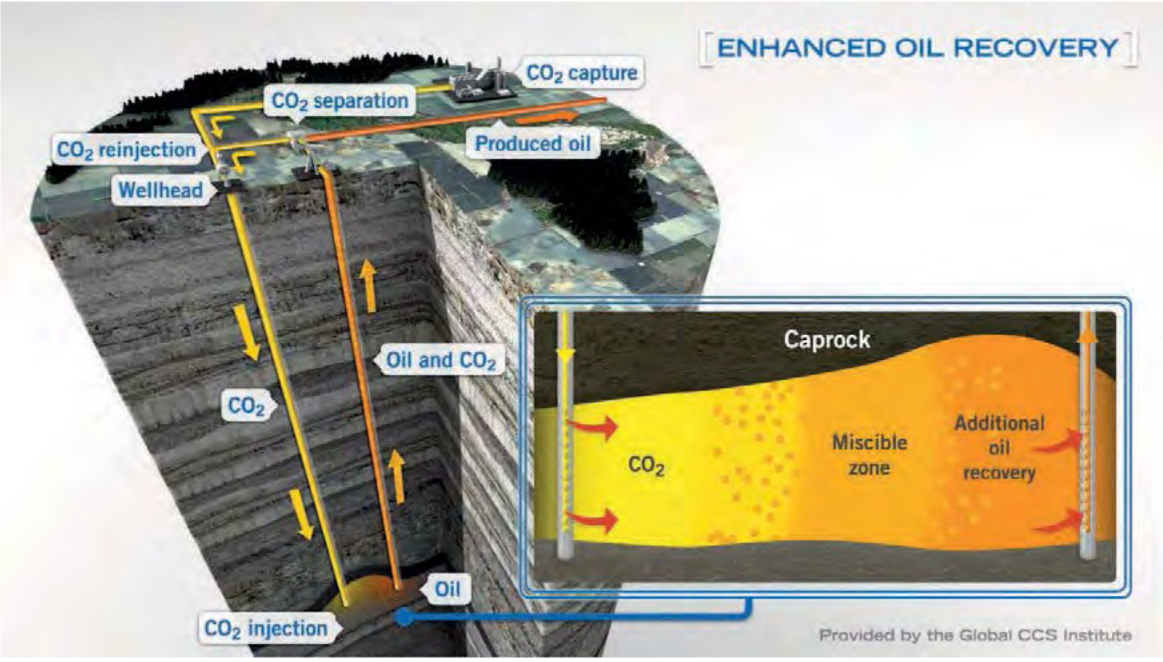
Oil fields typically have several production phases. While specifics will vary according to the characteristics of each field, they are often grouped in three main phases. In the first, **primary production** phase of an oil reservoir, oil flows to the production well as a result of pressure gradients within the reservoir. Initially this occurs naturally, but over time the oil production rate tends to decrease as ongoing production of fluids leads to a decline in reservoir pressure (at the same time rates of water production increase). At this point, producers may apply a range of **secondary** and **tertiary** techniques to enhance oil recovery and compensate for declining production.

Secondary recovery involves increasing pressure in the reservoir by injecting (through wells) a fluid, such as water or natural gas. The injected substance usually does not mix with the reservoir oil (i.e. it is "immiscible" with the existing oil), and has the effect pressurising the reservoir. Usually the injection strategy is designed to drive oil towards the production wells. In gas re-injection, a common variant of secondary recovery, natural gas produced during extraction is re-injected into the reservoir's gas cap, which overlies the oil, driving the oil downwards to the producers. Water flooding is usually targeted at the margins of the reservoir, to push (or sweep) the oil towards the wellbore.

A successful secondary recovery programme may boost the total recoverable oil by an additional 5% to 20% of the original oil in place. Such pressure maintenance programmes may begin during the primary oil production phase of an oil field, although water flooding and similar production enhancements are usually not required until well into a reservoir's productive life. As pressure maintenance with water is less costly than other techniques, it tends to be the secondary process of choice.

Tertiary recovery is the third level of production enhancement, one option for which is CO_2-EOR (a schematic explanation of the CO_2-EOR process is shown in Figure 1).

Figure 1 • Schematic of CO_2-EOR operation



Source: Global CCS Institute (2015), website, www.globalccsinstitute.com/content/information-resources.

In addition to maintaining pressure and sweeping oil to the production wellbore (as in secondary recovery), tertiary techniques aim to change the properties of the oil of reservoir rock, or alter flow patterns in the reservoir. This implies the need for substance that will interact with oil to alter its density or viscosity, change the "wettability" of the reservoir rock, or plug high-permeability flow paths in the reservoir.

Main methods include thermal recovery, chemical flooding and, miscible gas injection. The type of EOR technology suitable depends on the characteristics of a given oil reservoir and its state of depletion. Whether or not CO_2-EOR can be effectively applied to a given reservoir depends on three main factors: *i*) the geological and petrophysical characteristics of the reservoir; *ii*) the physical and chemical characteristics of the oil; and *iii*) the production history, condition and accessibility of the field.

CO_2, nitrogen and hydrocarbon gases (e.g. propane, butane) have been employed as injectants in tertiary recovery projects. In a miscible CO_2 displacement process relatively pure CO_2 (i.e. typically 95% by volume or greater) is injected into the reservoir and mixes with the oil. This has the effect reducing the capillary forces that trap the oil in the reservoir rock and creates more favourable flow properties. Compared with injection of nitrogen and hydrocarbon gas, CO_2 achieves miscibility with oil at lower pressure and can therefore be applied in relatively shallow reservoirs.

Pressure balance is critical to CO_2-EOR: to achieve miscibility, the reservoir pressure must be maintained above the so-called minimum miscibility pressure (MMP) while the maximum reservoir pressure is limited by the reservoir fracture pressure. Pressure can be maintained in this window by balancing the injection and withdrawal of fluids from the reservoir. Should it be impossible to reach the MMP, for instance in shallow reservoirs, CO_2-EOR can still be applied, but operated as an immiscible flood in which the injected CO_2 physically pushes the oil towards the production wells (as described under secondary recovery). Operating the CO_2 flood above the MMP is preferable as the miscible process leads to more efficient oil recovery (although some miscible benefits may be achieved even where full miscibility is not achievable).

One impediment to CO_2 flooding arises from the fact that the viscosity[2] of CO_2 under injection conditions is low compared to that of the oil; this creates a tendency for the CO_2 to channel or "finger" through to the production well without mixing with the oil to a significant degree. As CO_2 also tends to be less dense than the reservoir, it rises towards the top (referred to as gravity override) and does not evenly contact the reservoir. These effects can be amplified or diminished by the geology of the reservoir (Green and Willhite, 1998). One approach to overcome this impediment and to achieve relatively even mixing of the CO_2 through the reservoir is known as the "water-alternating-gas" (WAG) process, which involves injecting alternating slugs of CO_2 and water produced from the reservoir. The presence of water hinders the movement of CO_2 through the rock, thereby enhancing mixing. WAG decreases the CO_2 demand per barrel of oil recovered, which is advantageous in a situation where CO_2 must be purchased and represents a cost factor.

When CO_2 reaches the production well, it is typically separated from the produced hydrocarbon so that it can be re-injected (i.e. recycled). In commercial projects, CO_2 typically "breaks through" at production wells relatively rapidly following the start of injection. This recycling is done for economic reasons, as the purchased CO_2 comes at a cost to the operator. Over the life cycle of the EOR project, the CO_2 injection and recovery cycles are repeated many times, with smaller amounts of new CO_2 added to the project in each cycle.

The role of CO_2-EOR in global oil production is currently limited: more than 140 projects globally produce around 300 000 barrels per day (bbl/d) of oil (Kuuskraa and Wallace, 2014) – i.e. only 0.35% of global daily oil consumption. Almost all operating CO_2-EOR projects are concentrated in the mid-west United States, not all that far from where the technology was first developed.

The viability of CO_2-EOR projects in the United States depends largely on three factors:

- The existence of oil reservoirs in late stages of production with geological and petrophysical characteristics conducive to CO_2 flooding.
- The availability of inexpensive CO_2 sources and an extensive, built-for-purpose CO_2 pipeline system to deliver this CO_2 to projects. Most CO_2 used in EOR projects today comes from naturally occurring volcanic accumulations.
- The combination of a fiscal regime that supports EOR deployment to enhance energy security and a legal framework that facilitates development of EOR projects.

While the way in which these factors have emerged is very specific to the United States – in particular, the evolution of the CO_2 pipeline network and supply business – there is no reason that similarly supportive conditions for CO_2-EOR could not be created in other regions with suitable oil reservoirs.

What happens to the injected CO_2?

Not all of the injected CO_2 is recovered at the production wells. To maintain pressure above the MMP, operators must carefully balance the volume of fluids produced and injected: as oil is being

[2] How resistant a fluid is to flow under an applied pressure.

produced and removed from the system, roughly equal volumes of CO_2 and water must be injected (in WAG operations).[3] A significant portion the CO_2 in the reservoir remains trapped due to capillary forces that act to immobilise its movement within pores and through dissolution in residual oil and water present in the reservoir.

With each recovery cycle, more of the injected CO_2 is progressively retained until a significant volume is securely trapped. The volume of CO_2 that can be stored in this way depends on properties of the reservoir and the oil it contains, and on operational factors of oil production, including the duration of the WAG and the water/oil ratio used, well spacing, and the relative position of injection and producing wells.

To maintain pressure and production, the CO_2 retained (stored) in the reservoir must be compensated through injection of additional CO_2 (or water). The "recovery efficiency" quantifies how many tonnes of CO_2 are injected to recover an additional barrel of oil, with low efficiencies indicating more CO_2 storage. The Weyburn-Midale EOR project in 2012 was producing about 18 000 incremental barrels per day (bbl/d) with an injection rate of 13 000 tCO_2/d – or about 1.5 barrels per tonne. This injected CO_2 represents 6 500 t purchased and 6 500 tonnes recycled, or approximately 3 barrels per purchased tonne of CO_2 (IEA, 2014b; see also Box 1).

At the end of the CO_2 flood, the volume of CO_2 that remains in the reservoir has been "incidentally stored" over the course of numerous CO_2 recovery and re-injection cycles. A portion of this CO_2 is trapped in the reservoir through capillary forces and would be very difficult to remove; however, much of the CO_2 exists either in the form of free phase CO_2 or is dissolved within the mobile oil and could be recovered. This leaves the operator with the choice to either produce the CO_2 so that it can be re-used elsewhere in the field or resold, or alternatively to take measures aimed at long-term CO_2 storage in the abandoned reservoir. In larger projects, operators usually choose to recover and re-use the CO_2 injected in early phases for later phases.

This recycling effectively establishes a closed-loop for use of CO_2 with only a very small amount of fugitive emissions released to the atmosphere during handling the CO_2 at surface facilities. While quantitative data on fugitive CO_2 emissions from CO_2-EOR projects is limited, the literature indicates losses of less than 0.3 % of the total volume of CO_2 injected for the Elk Hills CO_2 project in the United States (Hill et al., 2013).

Has CO_2-EOR been used to store CO_2?

The increasing urgency to combat climate change has sharpened the focus on CCS and raised questions about the role that CO_2-EOR is currently playing in supporting CCS and the role it could play in geological CO_2 storage. There is growing recognition that CO_2-EOR can be a means of storing CO_2 and, thus, can indeed play a role in combating climate change.

However, most of the CO_2-EOR projects operating today use naturally occurring CO_2 that is extracted from underground specifically for EOR purposes. Such practice is neither beneficial for the climate nor for the development of CCS. Moreover, in most cases CO_2-EOR operations have not been designed with long-term CO_2 storage in mind and, hence, storage-focused activities that support the demonstration of long-term CO_2 storage have not been undertaken (e.g. risk assessment, monitoring and verification).

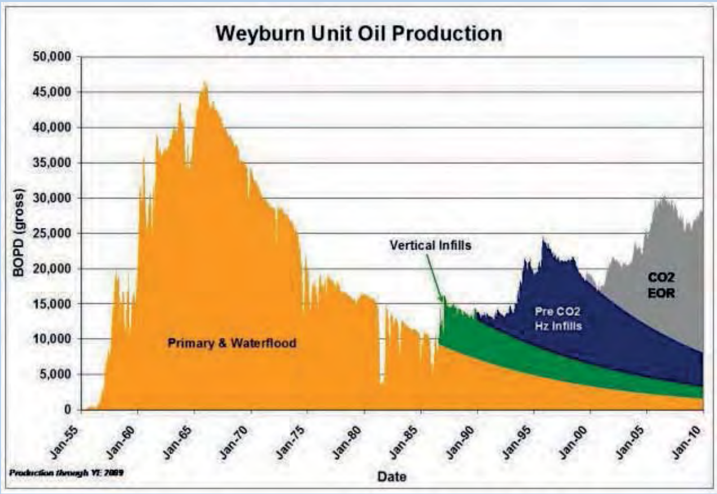
[3] To a first approximation, the reservoir can be considered a closed volume initially saturated with a mixture of oil and water: if oil is removed, another fluid must be injected to maintain a constant pressure. In reality, the presence of natural gas or the influx of water can complicate the calculation, but the principle remains the same.

The IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project has been an early exception, as it included an extensive pilot programme to monitor and verify the storage of CO_2, between 2000 and 2012 (Hitchon, 2012). Although the project no longer monitors the stored CO_2 and the field is operated as a traditional EOR project, it has provided very useful insights into the potential of combining two activities.

Box 1 • Weyburn-Midale: The front-runner in combining CO_2-EOR and CO_2 storage

The Weyburn and Midale oil fields, located in southeast Saskatchewan, Canada, were brought into primary production in 1954. As is common, oil was initially produced from the reservoir without injection of other fluids; however, over time, production has been maintained in both fields through the use of water flooding coupled with the drilling of additional (infill) wells to reach parts of the reservoir that had not been previously accessed. In October 2000, Cenovus (formerly PanCanadian or EnCana) began injecting CO_2 into the Weyburn field in order to boost oil production. There are now over 100 injection wells. Apache followed suit in 2005, injecting CO_2 into the Midale field.

The Weyburn and Midale fields combined are expected to produce at least 220 million barrels of incremental oil through miscible or near-miscible displacement with CO_2. EOR will extend the life of the fields by approximately two to three decades.



Source: Cenovus, http://en.wikipedia.org/wiki/File:Cenovus_Unit_Oil_Production.jpg.

What makes the Weyburn-Midale project unique among CO_2-based EOR operations is the comprehensive monitoring and verification pilot program undertaken between 2000 and 2012. Overall, it is anticipated that around 40 $MtCO_2$ will be permanently sequestered over the project's lifespan – 30 Mt at Weyburn and 10 Mt at Midale.

The key finding from this project relates to the successful coupling of EOR operations and CO_2 storage. Experience of the 12 years of operation clearly demonstrates that the two approaches can be complementary, that accurate CO_2 accounting is possible and that permanent storage of CO_2 can be achieved.

Knowledge and experience from both CO_2 capture and EOR are set to grow in the near future, as new projects are pursuing the dual ambition of using CO_2-EOR to reduce emissions and increase oil production (Box 2).

Box 2 • Examples of large-scale CO_2 capture projects linked with EOR

A number of new CO_2 capture projects in early operation or in construction are linked to conventional CO_2-EOR as practiced today. These projects will improve experience in large-scale capture of CO_2 from various sources, and EOR will provide necessary partial economic drivers and business models for the projects.

The Boundary Dam Unit 3, inaugurated by SaskPower in October 2014 (Saskatchewan, Canada), is the world's first large-scale power unit equipped with post-combustion CO_2 capture. This rebuild of an aging generator operates on continuous mode (producing 110 MW of power to the grid) and captures 95% of the CO_2 emissions (and 100% of the SO_2) of the lignite-fired power unit – reducing direct CO_2 emissions by 1 million tonnes per year (Mt/yr). The captured CO_2 is transported to nearby oil fields for EOR and a proportion is also stored in the associated Aquistore Project.

In the first half of 2016, the Kemper Project gasifier and capture unit, owned and operated by Mississippi Power (a subsidiary of Southern Company), is scheduled to come online in Mississippi, United States. This large-scale (582 MW) integrated gasification combined cycle (IGCC) plant will incorporate CCS technologies with the aim of significantly reducing the high emissions normally associated with transforming lignite coal into natural gas. The company intends to capture 65% of the plant's CO_2 emissions and hence deliver 3 $MtCO_2$ per year for EOR use in nearby fields.

Construction recently began on the NRG Petra Nova project in Texas (United States), a joint capture project by NRG Energy and JX Nippon Oil and Gas Exploration (with transport and storage held by Texas Coastal Ventures, a joint venture between Petra Nova Parish Holdings and Hilcorp Energy Company). This combined coal- (247 MW) and gas-fired (127 MW) plant is being retrofitted with post-combustion technology to capture 90% of emissions (1.4 Mt/yr), which would be fed into the West Ranch oil field (operational since 1938). Over the 20-year project span, the site may develop as many as 130 injection wells and 130 production wells.

Petrobras, BG Brasil and Petrogal Brasil are partners in the Lula oil field CO_2-EOR project located in the Santos Basin, some 300 kilometres off the coast of Rio de Janeiro, Brazil. The Lula project separates 0.7$MtCO_2$ per annum from natural gas production and injects the CO_2 for EOR in a pre-salt carbonate reservoir, some 5 000-7 000 metres below the sea level. The Lula project, in operation since 2013, is a pioneer in ultra-deep water CO_2-EOR, operating currently the deepest CO_2 injection well in the world.

In Saudi Arabia, Saudi Aramco is implementing the Uthmaniyah CO_2-EOR project. In this project, CO_2 is captured from the existing Hawiyah natural gas processing plant and some 800 000 tCO_2/yr will be injected in the Uthmaniyah production unit (part of the super-giant Ghawar oil field) for EOR. The project will pilot new technologies in order to monitor and verify the behaviour of CO_2 underground.

Operation of existing projects demonstrates that, to date, climate change mitigation and long-term CO_2 storage goals do not figure within the rationale for EOR projects in the United States (Dooley et al., 2010). This is not a surprise given the lack of a focus on climate mitigation during the development of the industry. Two main impediments appear to be standing in the way of using CO_2-EOR as a mitigation option:

- There are few incentives, commercial or otherwise, that would lead the operator of a CO_2-EOR project to focus on CO_2 storage. Hence, most projects do not undertake dedicated activities to demonstrate that CO_2 remains contained in the reservoir. Such monitoring activities are generally agreed to be a critical component of geologic CO_2 storage (e.g. see IPCC, 2006); thus, CO_2 injected in EOR projects cannot be considered "as not being emitted" in the framework of climate policy.
- The laws and regulations that apply to CO_2-EOR operations have evolved to address the issues associated with oil and gas operations, not CO_2 storage. In the United States, for example, property law places limits use of the subsurface that, while allowing for efficient oil recovery, present barriers to CO_2-storage (Marston, 2013). Without changes

to the laws and regulations that apply to CO_2-EOR, it may not be possible to reconcile the practice of CO_2-storage with that of CO_2-EOR.

Despite increasing interest worldwide in the potential for CCS as a climate change mitigation technology and the potential role CO_2-EOR could play in its deployment, few, if any, of the more recently identified opportunities have been developed outside the United States. In analysis carried out in the early 2000s, the International Energy Agency Implementing Agreement on Greenhouse Gas Research and Development Programme (IEAGHG) identified 488 CO_2-EOR candidate projects as “early opportunities” for CCS (Lysen, 2002).

Towards storing CO_2: "EOR+" as a climate tool

Key points

Extending CO_2-EOR practice to qualify as CO_2 storage can be achieved with adjustments to the design and operations of a CO_2-EOR project. At a minimum, these would include four main activities: i) additional site characterisation and risk assessment; ii) additional monitoring of vented and fugitive emissions; iii) additional subsurface monitoring; and, iv) changes to field abandonment practices.

Costs of undertaking CO_2-EOR for storage, i.e. EOR+, will be higher than for traditional CO_2-EOR due to additional monitoring, measuring and verification (MMV) and closure activities and could also increase as a result of changes to flood design and operations.

Storing CO_2 through EOR operations could be profitable, provided that the CO_2-EOR operators see the economic benefits of reducing emissions from large point sources and that these benefits are, at a minimum, greater than the additional costs associated with storage. As the benefits of reducing emissions grow, the profits from carbon storage activities lead to higher levels of CO_2 storage, particularly at higher oil prices. In fact, a case in which the amount of CO_2 used per barrel of oil is increased in order to recover additional oil, delivers greater overall profitability than traditional EOR across a wide range of future price scenarios.

However, oil price is the single most important driver for CO_2-EOR project economics, with higher prices catalysing higher levels of carbon injection.

Adding storage to CO_2-EOR: Minimum requirements for EOR+

The previous chapter described how CO_2-EOR is undertaken today. Oil producers are already injecting CO_2 into underground reservoirs, with the aim of enhancing the production of oil. In this section we will look at how CO_2-EOR could be used for climate change mitigation purposes.

Extending today's practice to qualify as CO_2 storage requires additional activities to be undertaken before, during and following CO_2-injection. At a minimum, these would include four main activities, the first two being pre-operational, the third and fourth during and following storage:

- **Additional site characterisation and risk assessment** to collect information on overlying cap-rock and geological formations, as well as abandoned wellbores, to assess the potential for leakage of CO_2 from the reservoir.
- **Additional measurement of venting and fugitive emissions** from surface processing equipment.
- **Monitoring and enhanced field surveillance** aimed at identifying and, if necessary, estimating leakage rates from the site to assess whether the reservoir behaves as anticipated.
- **Changes to abandonment processes** that help guarantee long-term containment of injected CO_2, such as plugging and removal of the uppermost components of wells so they can withstand the corrosive effects of CO_2-water mixtures.

These additional activities represent an additional cost to CO_2-EOR operators that would, if not offset by compensatory measures or revenue, negatively impact project economics. Thus, ensuring that operators take the steps of managing oil fields for both oil recovery and CO_2

storage requires a link between the regulatory framework for oil production and that for tackling climate change. The challenge for jurisdictions that already have CO_2-EOR activities is to make this transition, which can introduce additional new business risks, sufficiently attractive to operators who are comfortable with the status quo. This could be done for example through carbon pricing or a regulatory mandate.

In this new context, generators of CO_2 would choose to capture rather than emit CO_2 and subsequently look to verifiably store the CO_2, potentially through a third party such as an EOR operator. This would create a demand for verifiable storage from which CO_2-EOR operators could benefit through, for example, reduced supply prices or revenues from offsets or certificates. CO_2-EOR operators could seize the opportunity by undertaking activities to demonstrate long-term storage and optimising flood design for lower CO_2 prices or CO_2-storage revenues, which would result in additional oil recovery and CO_2 use. The feasibility of such a shift in operations depends on the relative prices of oil, the price of CO_2 supplied for EOR, energy costs (for processing and compression), and the cost of design and operation of EOR (e.g. additional wells, fluids separation and compression capacity).

EOR+: Three models – *Conventional*, *Advanced*, *Maximum Storage*

For the purposes of illustrating the needed changes in practices (and for the later purposes of identifying the associated global potential as discussed in the next chapter), we outline below three operational models, with significant differences in the way CO_2-EOR oil extraction and carbon storage activities interact. All three models assume the additional activities described above are undertaken, which would impose costs on the operator above and beyond those generally incurred today (i.e. the "*Conventional EOR+*" practice is distinct from CO_2-EOR as typically practiced today). The impact of the additional cost is examined in greater detail later in this section. In this sense, none of these models represent a "business-as-usual" approach. The three typologies are:

- ***Conventional EOR+***: As its name suggests, this model is based on CO_2-EOR operations as documented in the literature for historical and current US projects (e.g. EPRI, 1999; Jarell et al., 2002; Azzolina et al., 2015; Brock and Bryan, 1989). It assumes representative values for net utilisation of 0.3 tCO_2/bbl of oil produced and incremental oil recovery corresponding to 6.5% of the original oil in place (OOIP).[4] It is furthermore assumed that operators undertake all additional activities as outlined above, including monitoring and verification.
- ***Advanced EOR+***: In this model an operator chooses to use and store more CO_2 to recover more oil. In this scenario, the projects have a net CO_2 utilisation of 0.6 tCO_2/bbl with incremental oil recovery rising to 13% of OOIP. This is consistent with net utilisation in some recent projects. These levels of utilisation and recovery could be reached in several ways including well control schemes (Kovscek and Cakici, 2005) and some "next-generation" practices (ARI and Melzer Consulting, 2010).
- ***Maximum Storage EOR+***: Under this scenario CO_2-EOR operations are undertaken with a strong focus on CO_2 storage. Consequently, net CO_2 utilisation rises to 0.9 tCO_2/bbl while incremental oil recovery stays at 13% OOIP (i.e. the level achieved in the *Advanced EOR+*). This level of storage could be achieved by not re-injecting produced water into

[4] Net utilisation refers to the volume of CO_2 purchased per barrel of oil recovered. Gross utilisation, which is also sometimes quoted as a performance metric, is the volume of CO_2 injected (including recycle volumes) per barrel of oil recovered. Because it includes recycle volumes, gross utilisation is higher than net utilisation.

the oil reservoir or by using CO_2 in a once-through system where, instead of being recycled, produced CO_2 is injected into a saline aquifer – similar to “stacked storage” concepts (Hovorka, 2013).

Table 1 summarises the technical assumptions for each of the three scenarios regarding the modes of extraction, all of which cover only miscible CO_2 flooding.[5]

Table 1 • Specification of *EOR+* practices

Scenario	Description	Incremental recovery % OOIP	Utilisation tCO_2/bbl
Conventional EOR+	Miscible WAG flood with vertical injector and producer wells in a “five spot” or similar pattern. Operational practices seek to minimise CO_2 use.	6.5	0.3
Advanced EOR+	Miscible flooding following current best practices optimised for oil recovery. May also involve some “second-generation” approaches that boost utilisation and recovery.	13	0.6
Maximum Storage EOR+	Miscible flooding where injection is designed and operated with the explicit goal of increasing storage. Could include approaches in which water is removed from reservoir to increase available pore volume.	13	0.9

The different behaviour of project developers in these three models is presumed to be driven by (1) a requirement to undertake the additional storage-related activities, (2) changes in oil price and (3) CO_2 supply prices. Operations in the *Conventional EOR+* scenario are broadly representative of historic CO_2 and oil prices – that is prices below USD 50/bbl with corresponding CO_2 supply prices of around USD 20 per tonne. The *Advanced EOR+* scenario could emerge as a result of declining CO_2 acquisition prices, for example, resulting from an increasing cost to industry producers to dispose of their CO_2, (see Box 3) and increasing oil prices relative to the *Conventional EOR+* case, which would drive the operator to use more CO_2 to recover more oil. Finally, the *Maximum Storage EOR+* case could emerge if, instead of paying for CO_2, the operator was paid to store CO_2 at oil prices comparable to those in the *Advanced EOR+* case.

Box 3 • CO_2 supply prices and potential impacts of price on CO_2 emissions

In the United States, CO_2 supply prices for EOR have traditionally been tied to oil prices and are generally not public information. However, they are generally understood to be in the range of a “few dollars” per thousand standard cubic feet (Mscf). For example, Bliss et al. (2010) state that recent contracts have been priced CO_2 at USD 30/tCO_2 (USD 1.6/Mscf) at oil prices of USD 70/bbl. In addition, several CO_2-EOR producers (e.g. Denbury Resource, Kinder Morgan, and Occidental Petroleum) own large natural geologic accumulations of CO_2 (DiPietro et al., 2012). In these cases, the cost of CO_2 supplied to their EOR operations is far less, on the order of a few USD per tonne at comparable oil prices.

At current US CO_2 prices, CO_2-EOR is clearly profitable, as evidenced by the growing number of US projects (Kuuskraa and Wallace, 2014). In fact, as recently as 2012 reports and industry presentations stated that access to CO_2 supplies was holding back EOR project development (ARI and Melzer Consulting, 2010; ARI, 2011; NEORI, 2012).

[5] As discussed earlier, immiscible flooding is generally less efficient at recovering oil than miscible CO_2-EOR and as a result, this analysis does not include immiscible flooding.

Box 3 • CO_2 supply prices and potential impacts of price on CO_2 emissions cont'd.

Consequently, some have argued that the revenues from CO_2 sales to EOR can help support capture projects and, indeed this has been the case (see Boxes 1 and 2). However, others have pointed out that in a future where emissions of CO_2 to the atmosphere are priced (or otherwise limited) the supply of captured CO_2 may grow, depressing CO_2 supply prices for CO_2-EOR to the point that prices become negative – a boon for EOR operators, but a negative outcome for those capturing CO_2 (Dooley et al., 2010).

In addition to there being the potential for competition between CO_2 sources that drives down the price of CO_2 supply, there is also the potential for competition that limits just how low (i.e. negative) the CO_2 supply price can go. In this case, the competition for disposal of CO_2 could come from saline aquifer storage. For example, in the United States, Eccles et al. (2012) estimate that 275 $GtCO_2$ of storage could be available for under USD 5/tCO_2, which would set a limit to the price CO_2-EOR operators could expect to receive – transport bottlenecks notwithstanding. Nonetheless, in both the ETP 2 °C Scenario and 4 °C Scenario considered here (IEA, 2014a), the operator could expect to generate revenues from use of CO_2 for EOR by the end of the modelling period and, as the results will show, the choice of NPV maximising scenario is robust to CO_2 disposal price trajectory.

Regardless of the CO_2 supply price, however, CO_2-EOR project operators will only consider additional activities required for verifiable storage if they are required to do so through regulation or contract with a CO_2 supplier. The corollary to this is that the financial benefit of storing CO_2 must be sufficient to offset the cost of doing so – otherwise, operators will choose to use natural CO_2 (where it is available) or not pursue CO_2-EOR at all. The financial benefit could come about through a reduction in supply prices, as discussed above, or a variety of other mechanisms, such as: government incentives per tonne of CO_2 verifiably stored, or a tradable certificate system. Alternatively, a CO_2-EOR operator might undertake the additional activities and move to an EOR+ practice through regulatory measures and mandates imposed by government. In such a scenario, a government would simply "ban" conventional practice.

The economics of increasing CO_2 storage through CO_2-EOR: Illustrative cases

In a carbon-constrained world, storing CO_2 through EOR can be a positive NPV proposition for CO_2-EOR projects. This is illustrated here by modelling the financial performance of three hypothetical CO_2-EOR projects under three different CO_2 and oil price scenarios. These three projects are identical, save for the EOR+ operational model after which they are patterned: i.e. *Conventional EOR+*, *Advanced EOR+*, and *Maximum Storage EOR+*. The full set of assumptions is provided in Annex 1.

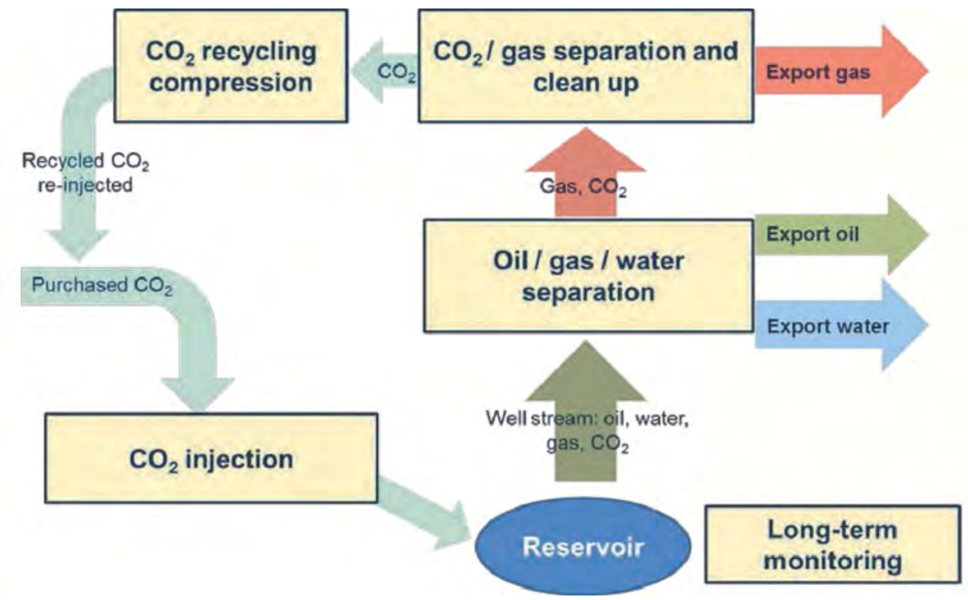
Capital and operating costs

To determine the costs of CO_2-EOR operations in the illustrative case, this analysis assumes a set of five core functional activities for which aggregated cost data have been developed (Figure 2).

- **CO_2 injection** includes distribution of CO_2 to the injection wells and all technical measures to maintain necessary pressure and temperature. The costs of CO_2 injection include the capital costs of compression, flow control and measurement, emergency blowdown equipment but do not include the capital cost of wells. The costs of well workovers, and drilling and completion for new injection wells as well as surface facilities is reported separately. The capital cost of CO_2 injection primarily depends on peak CO_2 handling rates.
- **Oil-gas-water separation** relates to activities required to manage produced fluids – i.e. the collection of fluids from the production wells; their transport to production facilities; the separation of oil, gas and water; the treatment of water for disposal; and the collection of gases for further processing.

- **CO_2-gas separation and clean-up** comprises activities to separate hydrocarbons from CO_2 and to adjust the composition of hydrocarbon streams to meet commercial specifications for export.
- **CO_2 recycling and compression** includes the compression of separated CO_2 and its mixing with new/purchased CO_2.
- **Long-term monitoring** pertains to measures needed to ensure the injected CO_2 remains contained in the reservoir, with data collection being the main cost item.

Figure 2 • Core functional activities used in cost analysis

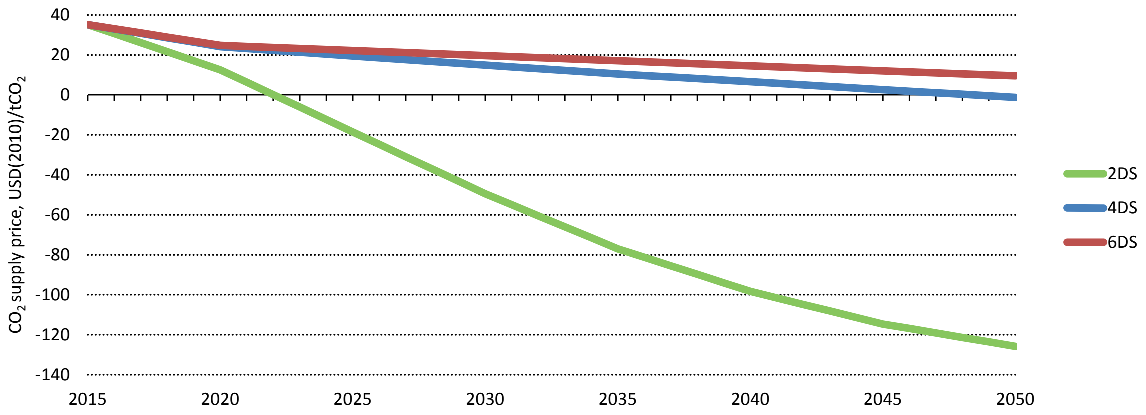


The "CO_2 supply price"

For the purposes of this analysis we consider the costs of CO_2 supply from the perspective of the EOR operator. The cost of CO_2 supplied for EOR is a key price signal for the oilfield owners' decision making. In reality, price formation for CO_2 supplied to EOR is complex. In this paper, the supply price of CO_2 simply means how much the field operator pays (or is paid) to acquire CO_2. The supply price is assumed for simplicity to be equal to the difference between the CO_2 emission penalty imposed by carbon policy (i.e. a carbon price) and the technical cost to the emitter of capturing CO_2. A positive CO_2 supply price indicates that it cost more to capture CO_2 than to pay the emissions penalty imposed, in which case the CO_2 emitter would sell CO_2 to the EOR operator, as is commonly the case today. In contrast, a negative supply price indicates that the emissions penalty is higher than the cost to capture CO_2. This creates incentive for the emitter (or "capturer") to pay for the CO_2 to be verifiably stored, in this case by the operator of an *EOR+* project, who will use it for EOR and ultimately store it in the oil reservoir.

The CO_2 supply prices are derived from the global average CO_2 emissions penalty in the *ETP* 2014 2 °C Scenario (2DS), 4 °C Scenario (4DS) and 6 °C Scenario (6DS). The average cost of capture is assumed to be USD 40/tCO_2 (in 2013 constant terms) for capture from anthropogenic sources.[6] The resulting CO_2 supply price for the different scenarios is set out in Figure 3. As reflected in this figure, the resulting CO_2 supply price trajectories vary significantly between *ETP* scenarios (Figure 3). Under the 6DS and 4DS, which have lesser climate mitigation ambitions, the price remains positive; i.e. as is the case today, the EOR operator pays the supplier for acquisition of CO_2. In contrast, under the 2DS, where emissions are constrained to limit the long-term average temperature rise to 2 °C, CO_2 supply price decreases steadily through to 2050 reaching USD 125/tCO_2 – i.e. the EOR operator would be paid by a supplier (e.g. industry) to store the CO_2.[7]

Figure 3 • Average CO_2 supply prices under three scenarios



The oil price received by EOR+ operators

Oil price trajectories are taken from the ETP 2014 2DS, 4DS, and 6DS. It is assumed that the *EOR+* projects all receive the same price for their produced oil – that is there is no differentiation of first purchase price on the basis of embedded upstream CO_2 emissions. Figure 4 shows the assumed price trajectories.

NPV of the different EOR+ models

NPV is used to compare the economic attractiveness of the three different *EOR+* projects patterned on the models above. It is essential to recall that the NPV is based on not only an estimation of the costs and revenues related to storing CO_2, but also the costs and revenues related to the oil production activities of the three *EOR+* projects. The oil price and CO_2 supply price are based on the three ETP 2014 scenarios (Figures 3 and 4), while capital and non-CO_2 operating costs are assumed to be constant across the three scenarios. NPV is calculated on the basis of a 10% discount rate, but excludes taxes and royalties, as they vary widely among jurisdictions. Following standard industry practice, the hypothetical projects are ended when operating costs exceed revenues; this analysis does not consider abandonment costs.

[6] The current actual cost of capture varies widely in different applications, from around USD 20/tCO_2 for processes that already generate concentrated CO_2 (e.g. natural gas sweetening, ammonia, some biofuels) to as much as USD 70/tCO_2 for capture from combustion flue gas in a power plant. This analysis does not take into account any potential competition between CO_2 suppliers.

[7] As mentioned earlier in Box 3, the definition of the supply price ignores any competing CO_2 disposal options, which, in reality, would limit the decrease in CO_2 supply price where they were available.

Figure 4 • Oil price trajectories under three scenarios

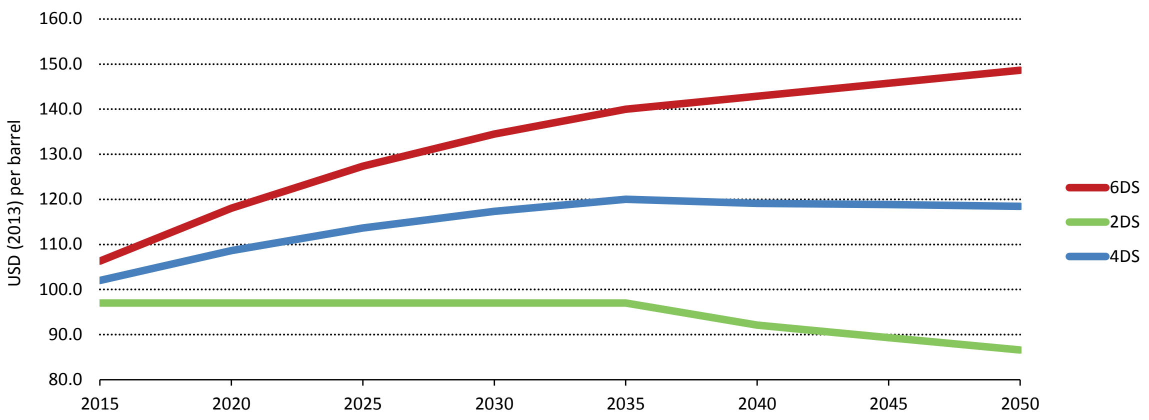
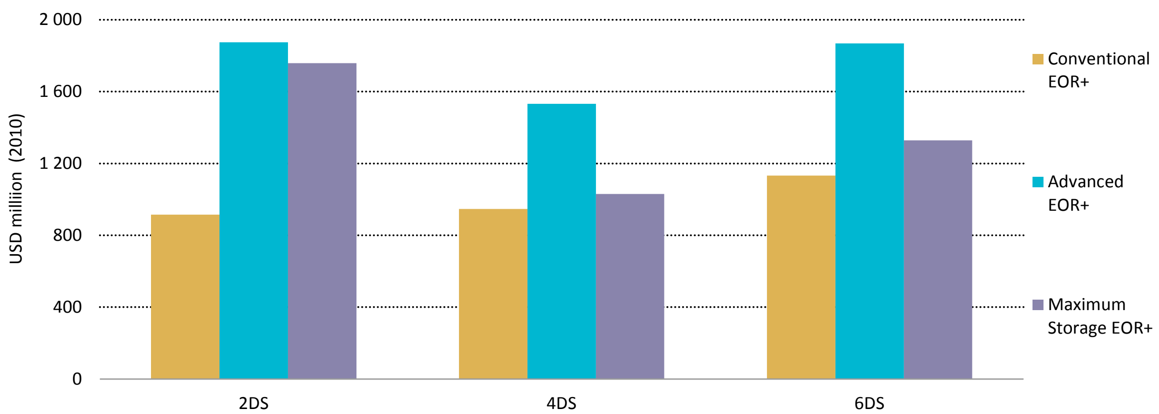


Figure 5 sets out the results and illustrates both how each hypothetical *EOR+* project compares to the others under a particular ETP price scenario. The first observation is that *Advanced EOR+* has a higher NPV than both *Conventional EOR+* and *Maximum Storage EOR+* practices under all ETP scenario price trajectories (Figure 5). The primary economic advantage of *Advanced EOR+* over the other practices results from increased oil recovery. This NPV advantage is most pronounced in the 2DS where *Advanced EOR+* increases the NPV by over 60% in relation to *Conventional EOR+*. The NPV advantage of *Advanced EOR+* relative to *Maximum Storage* is 30% to 40% in the 4DS and 6DS, but drops to less than 10% under the more aggressive carbon constraints of the 2DS.

Figure 5 • NPV of illustrative CO_2-EOR project for different ETP scenarios and using different EOR practices

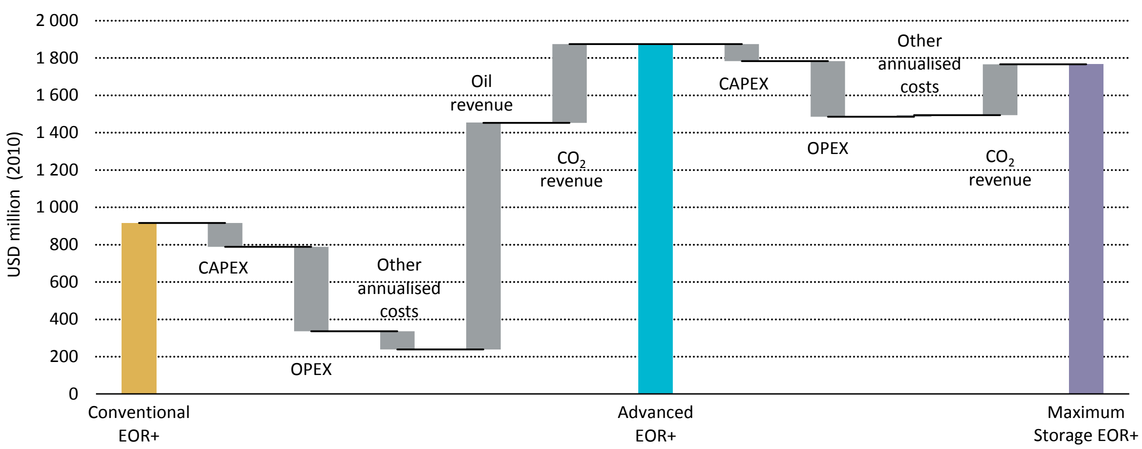


Despite the dominance of *Advanced EOR+* across all three scenarios, somewhat surprisingly, the NPV of *Advanced EOR+* is smallest in the 4DS compared to both the 2DS (high climate ambition) and the 6DS (lowest climate ambition) cases. This is principally the result of CO_2 being a cost to the project (i.e. a positive supply price) in the 4DS but shifting to a revenue stream in the 2DS; however, for *Conventional EOR+*, the changes in oil prices and CO_2 supply cost between the 2DS and 4DS offset one another. The increasing value of the oil recovered does not offset the increase in operating costs in *Advanced EOR+* between the 2DS and 4DS, but does make a significant impact between the 4DS and 6DS.

The results showing the comparative profitability of *Advanced EOR+* remain robust against a broad range of changes in the performance parameters (see Annex 1). There are several additional salient observations which can be drawn from Figure 6, in which the factors contributing to the different project NPVs are split out:

- Under the 2DS, increased oil recovery delivers three-quarters of the increased revenues of *Advanced EOR+* relative to *Conventional EOR+*, despite the operator being paid over USD 100/tCO_2 by the late 2030s. This reflects the fact that even though the 2DS delivers on ambitious climate change mitigation targets, hydrocarbons are, nonetheless, still highly valued.
- In addition, the increased costs associated with *Advanced EOR+* relative to *Conventional EOR+* are almost fully covered by revenues from CO_2 storage – making the increase in oil revenue effectively free.
- Moving from *Advanced EOR+* to *Maximum Storage* there is no increase in oil production, leaving only revenue from CO_2 storage to defray the added costs of increased CO_2 injection. Even under the 2DS, the revenue from CO_2 storage is insufficient to fully cover the costs of increased injection.

Figure 6 • Factors contributing to the different NPV results for each CO_2-EOR practice under the 2DS



Notes: Other annualised costs include changes to produced water management and CO_2 storage monitoring costs. CAPEX = capital expenditures; OPEX = operational expenditures.

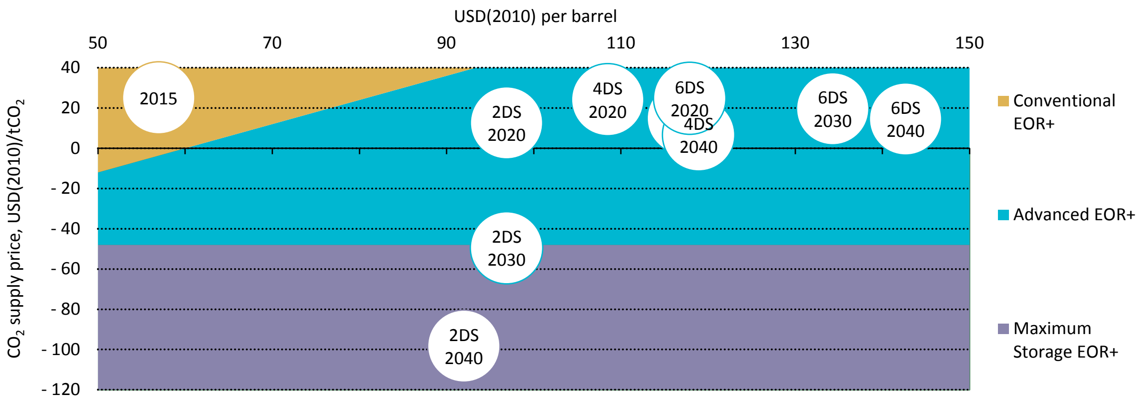
The largest contribution to uncertainty in the NPV for all three EOR practices under the 2DS is the injection rate per well, and hence the number of new wells required in the hypothetical project (see the technical appendix for further detail). This is followed by the incremental oil recovery and parameters affecting the oil production profile – namely the time to plateau and decline rate. Nonetheless, *Advanced EOR+* is more attractive than *Conventional EOR+* across a wide range of parameter values under 2DS price trajectories.

Price drivers for Conventional, Advanced *and* Maximum Storage EOR+

In addition to analysing the NPV under the ETP price scenarios for CO_2 supply and oil prices, Figure 7 shows the preferred (i.e. highest NPV) scenario for a wide range of CO_2 supply and oil prices. One of the central insights from this illustrative analysis is that *Advanced EOR+* practices are more attractive than *Conventional EOR+* practices not only at lower (and negative) CO_2 supply prices, but also at higher oil prices. The reason for this result is that, as noted above, we assume additional injection (and related additional storage) allows for increased oil production.

Since *Advanced EOR+* and *Maximum Storage* show the same dependency on oil price, the CO_2 supply price alone determines their relative economic attractiveness. Assuming that the oil and CO_2 supply prices are fixed over the lifetime of the project, the area in which the NPV of *Advanced EOR+* is higher than that for *Maximum Storage* is separated by a straight horizontal line in Figure 7. Average supply prices above USD 50/tCO_2 are required for *Maximum Storage* to become economically attractive, which are only achieved in the 2DS from about 2030 onward.

Figure 7 • Illustrative oil and CO_2 price impact on choice of EOR+ practices in different scenarios



Note: It is assumed that regulation or other climate policies exclude the possibility of undertaking EOR without the additional monitoring and verification practices designed to permit CO_2 storage tracking for mitigation purposes (i.e. all EOR is "*EOR+*").

In summary, the results presented here illustrate that the oil price, rather than the CO_2 supply price, is the bigger determinant of the economic attractiveness in choosing between different *EOR+* practices. The results also indicate that increasing utilisation rate of CO_2 above that required to increase oil recovery is only economically favourable at highly negative supply prices (i.e. above around USD 60/tCO_2, i.e. the EOR operator needs to receive significant compensation for storing CO_2). Together, these factors explain why *Advanced EOR+* is the NPV maximising choice under all three price trajectories considered. These findings are consistent with those from previous work by Leach et al. (2011), in which the authors concluded that CO_2 use in EOR projects is relatively insensitive to changes in CO_2 prices, but very sensitive to oil prices.

The above results also suggest that at higher oil prices, and assuming relatively modest CO_2 supply prices, it would be beneficial to inject more CO_2 and extract more oil than historically has been the case, regardless of the storage benefits. This finding, of course, hinges on the assumption that the marginal recovery rate from injecting an additional barrel of oil is positive – as is assumed in the *Conventional EOR+* case.[8]

The economic attractiveness of *EOR+* illustrated by this analysis, and in particular *Advanced EOR+*, mean that CO_2-EOR could indeed be an important means of storing CO_2. However, these results also beg the question of why more CO_2-EOR projects are not being implemented globally. The following sections examine the technical potential for CO_2-EOR and the emissions reduction benefit that might come from CO_2-EOR.

[8] There is some evidence to support this, as more recently reported utilisation rates are higher than those reported based on 1970s and 1980s practice (Azzolina et al., 2015; Murrell and DiPietro, 2013; DNR, 2014).

The global technical potential for EOR+ for CO_2 storage and oil production is large

Key points

At the global level, a substantial opportunity for CO_2 storage through EOR+ exists, ranging from 60 $GtCO_2$ to 360 $GtCO_2$ globally in the next 50 years. This level ranges from 50% to more than three times the amount of total CO_2 storage required under the IEA 2DS scenario through 2050.

In addition to storing more CO_2, Advanced EOR+ could potentially increase oil production as compared to conventional EOR+ (which uses less CO_2) over the next 50 years by up to 375 billion barrels.

While the overall potential to store CO_2 via EOR+ is indeed very significant, this opportunity is not evenly distributed in the world. Middle East, Russia, North Africa and Central Asia account for about 90% of the global technical potential outside the United Sates as measured by either oil production or CO_2 storage.

To analyse how much CO_2 could be stored and how much oil could be produced using *EOR+* globally, a field-by-field evaluation of suitability and capacity has been undertaken, using a rich oil industry dataset. The dataset has been screened applying the CO_2 utilisation rates and oil recovery factors assumed in the three practices presented in the previous section (see Table 1), effectively creating three scenarios.

It is stressed that this analysis remains on the technical level, i.e. trying to shed light as to how large the physical opportunity would be around the world. Economic considerations (such as those outlined in the illustrative case study in the previous section) were not part of the screening process. Thus, the results provide information on the *technical potential* associated with each type of *EOR+* scenario, which can be viewed as an upper limit to the amount of oil that could be recovered and CO_2 stored based on the best available data in 2012. The actual potential that might be implemented will depend on various other considerations, primarily economic and political.

Table 1, presented earlier, summarises the assumptions for each of the three scenarios, all of which cover only miscible CO_2 flooding. As discussed earlier, immiscible flooding is generally less efficient at recovering oil than miscible CO_2-EOR and as a result, this analysis does not include immiscible flooding. The criteria are used to screen the UCube[9] global upstream database to identify fields amenable to CO_2-EOR flooding. Ultimately, this makes it possible quantify the global volumes of oil that can be recovered and of CO_2 that can be stored for each of these CO_2-EOR practices.

The screening process for this analysis included all fields that are currently producing, abandoned or planned to start production before 2025. It assumes oil recovery factors and storage volumes achievable with technologies known today, but it must be noted that the equations will change

[9] UCube, compiled by Rystad Energy, is a field-level database with global coverage, containing information on around 65 000 oil and gas fields, as well as licenses and portfolios of 3 200 companies. Assets are characterised by parameters pertaining to location, hydrocarbon flow properties (e.g. density, viscosity, composition), geophysical field characteristics (e.g. pressure, porosity, permeability), and the state of production. The data in UCube originate from primary sources such as company and government reports. Where detailed information is not available, completeness of the database is ensured through estimates or modelling. The modelling is used to forecast future production from fields and to estimate yet-to-find volumes in licenses.

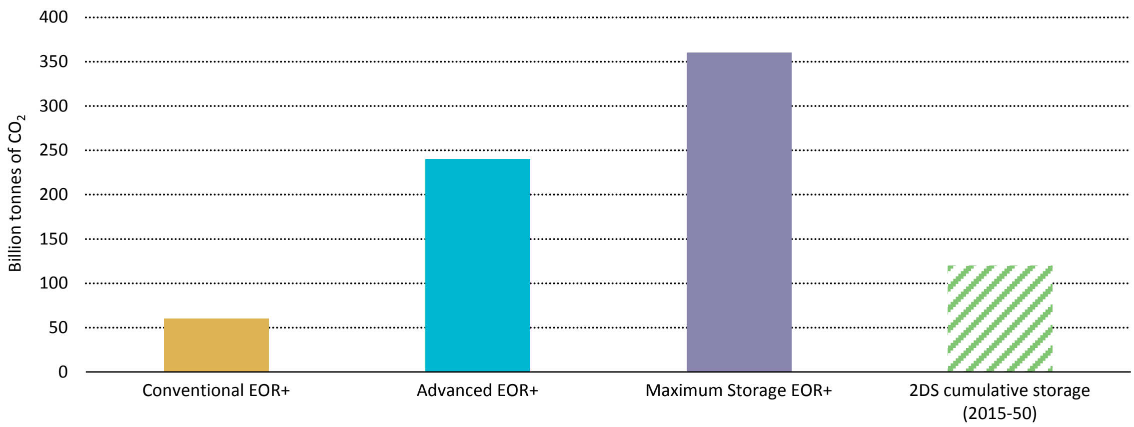
as technology advances. Additionally, the emergence of policies constraining CO_2 emissions could trigger important changes for the economics of CO_2-EOR and storage operations, having impacts on both CO_2-EOR technology and practice.

Recognising that the design and operation of a CO_2-EOR project can be optimised for a wide range of conditions, it is necessary to make certain assumptions about how oil recovery operations might be conducted. Because this study is interested in the potential for CO_2 storage, this assessment is based on three different scenarios that represent different points on the design and operational spectrum, which each imply different levels of CO_2 consumption.

The aggregate technical potential for storage and oil recovery

There is a substantial opportunity for CO_2 storage through *EOR+*. The technical potential of *Conventional EOR+* practices to store CO_2 amounts to about 60 $GtCO_2$ globally over the next 50 years (Figure 8), representing more than half of the total CO_2 storage needed to keep the world on the IEA 2DS trajectory. *Advanced EOR+* delivers a technical potential of 240 $GtCO_2$, which exceeds the IEA 2DS requirement for CO_2 storage. *Maximum Storage* totals 360 $GtCO_2$. These figures do not account for the potential additional miscible CO_2-EOR, which might add a further storage potential of 30 $GtCO_2$.

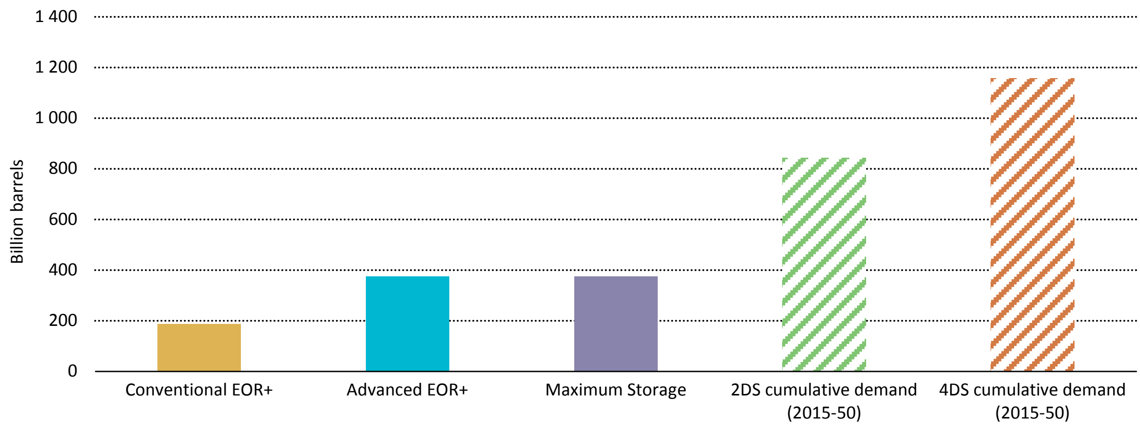
Figure 8 • Global storage potential for different CO_2-EOR practices ($GtCO_2$)



The corollary to increased CO_2 storage is increased oil production. Where the CO_2 storage potential is large, a similarly substantial opportunity exists in terms of the potential of EOR to produce additional oil. From a technical standpoint, *Conventional EOR+* practices could deliver about 187 billion barrels (Bbbl) of additional oil. Widespread application of the practices implied in the *Advanced EOR+* or *Maximum Storage* scenarios could increase global oil production over the next 50 years by up to 375 Bbbl (Figure 9), i.e. corresponding to over ten times the current yearly oil consumption. As is expected from the scenario specification, CO_2-EOR practices aimed at achieving *Maximum Storage* do not further increase oil recovery over the *Advanced EOR+* option; they do, however, change estimates for CO_2 stored. The incremental production resulting from immiscible CO_2-EOR is small at 56 Bbbl over the next 50 years, but if applied could increase the incremental production up to a total of 431 Bbbl.

Roughly three-quarters of the potential additional oil is likely to be from onshore fields, and the remaining quarter from offshore. It should be emphasised that these estimates are purely based on technical considerations, and that the actual amount of CO_2 stored and oil recovered will likely be less. Factors that will influence the uptake of CO_2-EOR practices include the availability and price of anthropogenic CO_2, oil prices, the cost of applying CO_2-EOR in various particular circumstances, and government policies. Significant differences exist in how this global potential is distributed geographically.

Figure 9 • Global incremental oil production potential for various CO_2-EOR practices



Geographic distribution of technical potential

The opportunity to store CO_2 and produce oil through CO_2-EOR is not evenly distributed around the world. With geological conditions being so vital to CO_2-EOR and CO_2 storage, some regions are simply better endowed with resources than others. In fact, excluding North America, just four regions account for about 90% of the global technical potential measured by either oil production or CO_2 storage under the Maximum Storage scenario, as outlined below (Figure 10).

- With over 70 $GtCO_2$, **Russia** has the largest technical potential, with most of this in Western Siberia (e.g. Khanty-Mansi) followed by southern Russia.
- In the **Middle East** region, Saudi Arabia, the United Arab Emirates, Iraq and Iran each have 25 $GtCO_2$ to 30 $GtCO_2$ technical potential. The total technical capacity to store CO_2 via EOR in the Middle East could amount to more than 100 $GtCO_2$.
- Significant potential also exists in **North Africa**, with Libya (24 $GtCO_2$) and Algeria (8 $GtCO_2$) being the main players.
- In the **Central Asia**, the greatest potential is found in Kazakhstan (9 $GtCO_2$) and Azerbaijan (9 $GtCO_2$).

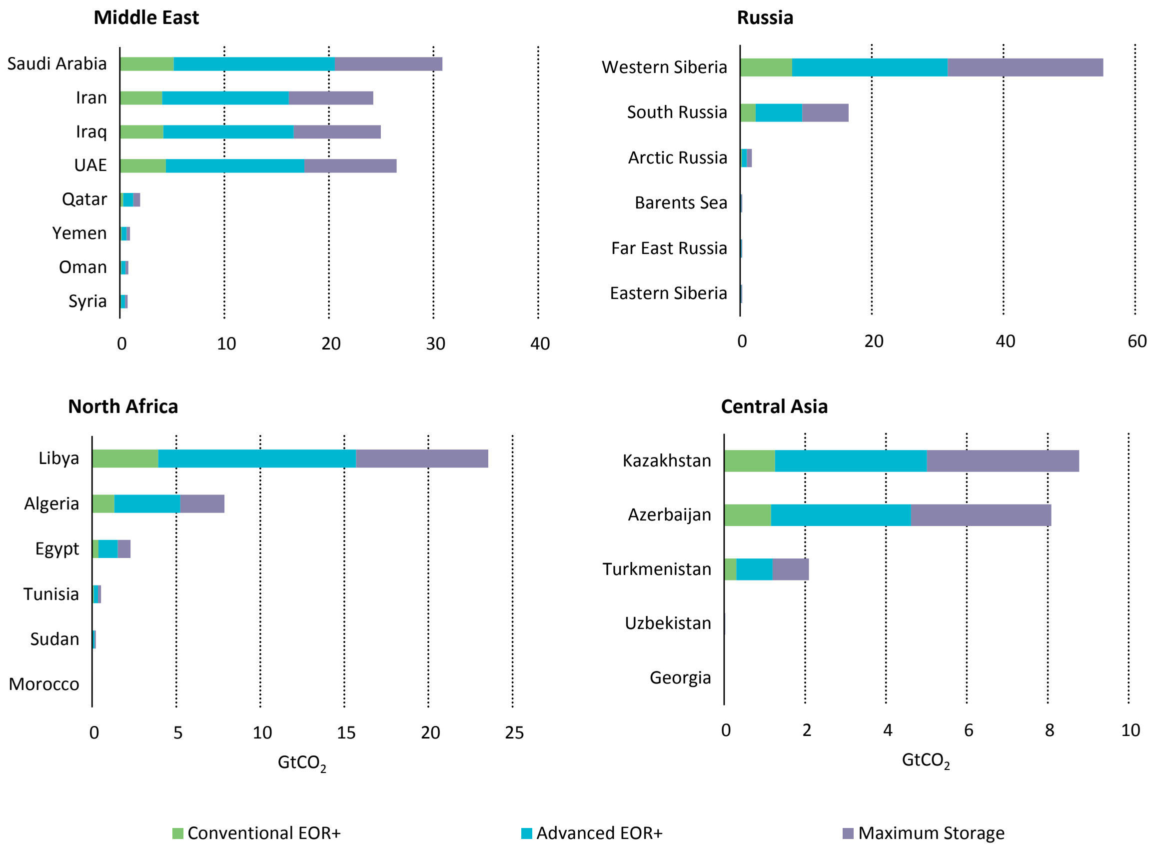
Outside these four regions, this analysis finds about 10 $GtCO_2$ of technical potential in North America under the *Maximum Storage* scenario. However, several studies indicate that the potential in North America may be of the same order as that of countries in the Middle East.[10]

[10] While 10 $GtCO_2$ corresponds to nearly 20 times the estimated amount of CO_2 stored in all North American CO_2-EOR operations to date (Hill et al., 2013), it is a much smaller potential than estimated in US-focused studies. For example, the most recent assessment by Advanced Resources International (ARI) for the US National Energy Technology Laboratory concludes that, depending on the scenario, between 62 and 119 Bbbl are technically recoverable from conventional reservoirs in the United states, while at the same time storing between 25 and 38 $GtCO_2$ (NETL, 2011). This is similar to a US estimate of 60 Bbbl and 17 $GtCO_2$ in a global assessment by ARI and Melzer Consulting (2009) for IEAGHG. Hence, these studies indicate that the potential in North America is of the same order of magnitude as that of the top countries in the Middle East. The discrepancy between this study and past US-focused studies is the result of relatively poor data coverage for US assets in the underlying database, and does not stem from a difference in views of the underlying geological potential.

It is noteworthy that while the above four regions show the most significant potential, the only CO_2-EOR project being implemented in the four regions is Saudi Aramco's Uthmaniyah CO_2-EOR demonstration project in Saudi Arabia, scheduled to start operation in 2015 (see Box 2).

Global incremental oil production potential under *Conventional EOR+* is 187 Bbbl. It almost doubles in the *Advanced EOR+* and *Maximum Storage* scenarios to about 375 Bbbl, with 70% of this potential coming from onshore fields The same four regions – the Middle East, Russia, North Africa and Central Asia – account jointly for about 75% of the technical CO_2-EOR potential for incremental onshore production.

Figure 10 • Storage potential in the top four regions



Understanding the global and regional technical potential for CO_2-EOR to boost incremental oil production or support CO_2 storage gives indication of where more detailed analysis would be useful. However, technical potential is ultimately insufficient for assessing whether the scope of CO_2-EOR as a CO_2 emission mitigation option is attractive as a new line of business for the oil industry. For this, it is imperative to calculate the cost and benefits of the technology and evaluate the availability and cost of CO_2 for injection. Providing robust answers would require geographically detailed studies on the potential to match existing and future CO_2 sources to available reservoirs in relevant regions (e.g. Ambrose et al., 2009), which is beyond the scope of this analysis but warrants further investigation.

Impact of widespread EOR+ on oil markets and global CO_2 emissions

Key points

CO_2-EOR results in storage of CO_2. However, CO_2-EOR also produces oil, the majority of which is burnt as fuel, generating CO_2 emissions. This will temper the net emission reductions achieved.

Understanding the net CO_2 emissions benefit of EOR on both project level and globally is a complex task. It requires thorough analysis and clear decisions regarding the included elements ("project boundaries").

The previous sections have highlighted the economic benefits of CO_2-EOR as an emissions reduction tool. While it is clear that CO_2-EOR can be an economic means of storing CO_2 (and producing oil), the emissions reduction benefit of CO_2-EOR is tempered by the production of additional fossil fuels, from which the majority of the carbon is inevitably emitted back to the atmosphere. From this perspective, storing captured CO_2 in a saline aquifer is, *ceteris paribus*, a more effective means of reducing emissions to the atmosphere. The following sections illuminate some of the key factors in assessing net CO_2 emissions for CO_2-EOR through a quantitative, life-cycle assessment of emissions for the models described earlier. While the high-level conclusions are informative, further analysis is required taking into account the varying underpinning assumptions. Hence specific results will vary from project-to-project.

Accounting for carbon at the project level

Each tonne of CO_2 delivered to a CO_2-EOR project is injected into the oil reservoir where, as described earlier, it mixes with the oil present in the reservoir making it easier to recover. The injection rates of CO_2 (and water) and production rates of fluids (oil, water and CO_2) are managed to maintain a constant pressure – ideally just above the MMP. Thus, for each barrel of oil produced, an equivalent volume of CO_2 and water (in WAG operations) remains in the reservoir; however, because some of the injected CO_2 mixes with the produced oil or bypasses oil in the reservoir, only a fraction of the CO_2 injected in one cycle is stored. That which is not stored is separated from the produced fluids and recycled to be injected once again.

Hence, over the life of a project each tonne of CO_2 delivered to the project is stored in the reservoir. Thus, in the three *EOR+* models described here – namely *Conventional EOR+*, *Advanced EOR+* and *Maximum Storage EOR+* – the amount of CO_2 stored is approximately equal to their net utilisation of CO_2 (Table 2).

At the project level, the amount of CO_2 stored is offset by emissions from the project both directly (i.e. fuel combustion, flaring, venting, and fugitive emissions) and indirectly due to the electricity used by the project. In the case of CO_2-EOR, the energy requirements – and hence indirect emissions – can be substantial because due to CO_2 recycling and, should it be required, processing of the recycle gas to separate natural gas liquids (NGL's) (Cooney et al., 2015). For a typical US project with NGL separation, Cooney et al. (2015) estimate emissions of 91 to 165 kilogrammes (kg) CO_2-eq per barrel of produced crude; without NGL separation, emissions would be approximately one-third lower.

Table 2 shows the emissions associated with each of the three practices for an example EOR project on the basis of both one barrel of produced oil and one tonne of CO_2 delivered to the project.[11] These figures show that net utilisation is a key factor in determining the emissions from CO_2-EOR projects and that, for the practices considered here, project-level emissions are negative where the CO_2 comes from an anthropogenic source – and ignoring any emissions that may be associated with capture and transport of this CO_2.[12] Of course, when CO_2 is supplied to the project from natural sources, no emissions reduction benefit can accrue to the project.

Table 2 • Illustrative project-level carbon balance of three *EOR+* practices

Scenario	*Conventional EOR+*		*Advanced EOR+*		*Maximum Storage EOR+*	
Net utilisation (tCO_2/bbl)	0.3		0.6		0.9	
Functional unit	1 tCO_2 delivered	1 bbl produced	1 tCO_2 delivered	1 bbl produced	1 tCO_2 delivered	1 bbl produced
Recycle (tCO_2)	0.98	0.29	0.98	0.59	0.98	0.88
Recycle losses (tCO_2)	0.01	0.00	0.01	0.01	0.01	0.01
Storage (tCO_2)	0.99	0.30	0.99	0.59	0.99	0.89
Emissions (tCO_2-eq)	0.23	0.07	0.16	0.09	0.13	0.12
Net emissions (tCO_2-eq)	**-0.76**	**-0.23**	**-0.83**	**-0.50**	**-0.86**	**-0.77**

Expanding the boundaries: Emissions from consumption of oil

Each barrel of oil produced from a CO_2-EOR project will be sold into the market, transported to a refinery where it is refined into a range of products, predominantly fuels, which are ultimately burnt to provide energy. The emissions associated with these steps vary with the quality of the crude oil, the relative location of production and consumption, and the slate of products into with the crude oil is converted (Gordon et al., 2015). The combustion of fuels produced from one barrel of conventional crude oil results in approximately 430 kg CO_2-eq of greenhouse gas emissions (EPA, 2014; Gordon et al., 2015). Transport and processing of conventional crude oil to produce these fuels increases emissions by slightly less than 10%, bringing the total emissions to around 470 $kgCO_2$-eq per barrel (Gordon et al., 2015).

Table 3 shows that when the downstream emissions from combustion of petroleum products are included (assuming that all *EOR+* production represents *additional* oil consumption), *Conventional EOR+* practices result in emissions of CO_2. However, even in this analysis in which no displacement of oil production is assumed (see next section), *Advanced EOR+* and *Maximum Storage EOR+* cases generate emissions reductions (albeit small in the former case) because of the increased amount of CO_2 stored per barrel of oil produced. These results are consistent with those presented by recent studies (e.g. Jaramillo et al., 2009; Wong et al., 2013).

[11] Underlying assumptions: CO_2 retention (as defined by Azzolina et al., 2015) of 0.5 for all of the operational cases; recycle losses of 1% of the CO_2 produced; recycle electrical energy requirements of 120 kWh/tCO2 recycled; grid electricity emissions intensity of 611 $kgCO_2$/MWh (Cooney et al., 2015); flaring, venting, and fugitive emissions of 44 $kgCO_2$-eq/bbl, which is the average of upstream emissions for "conventional" crudes reported by Gordon et al. (2015). The electricity consumption assumed here is consistent with a project without NGL separation (Cooney et al. 2015).

[12] Expanding the boundaries to include CO_2 capture in the assessment requires judgement to be made about allocation of the emissions between a product such as electricity and the captured CO_2, greatly increasing the complexity of the analysis. See Jaramillo et al. (2009) or Cooney et al. (2015) for assessments of CO_2-EOR including both emissions associated with CO_2 supply and use of oil products.

Table 3 • Illustrative carbon balance of three *EOR+* practices including combustion of the produced oil

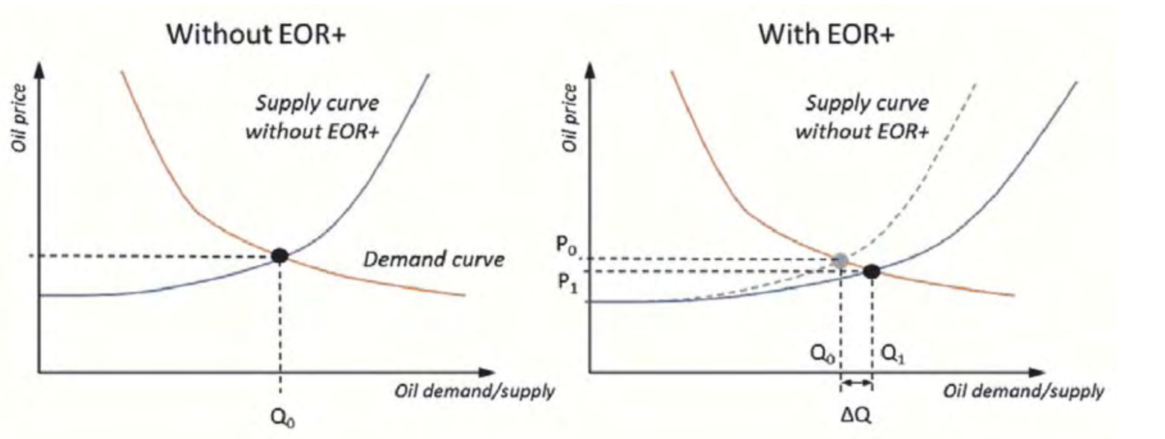
Scenario	*Conventional EOR+*		*Advanced EOR+*		*Maximum Storage EOR+*	
Functional unit	1 tCO_2 delivered	1 bbl produced	1 tCO_2 delivered	1 bbl produced	1 tCO_2 delivered	1 bbl produced
Downstream emissions from oil use (tCO_2-eq)	1.56	0.47	0.78	0.47	0.52	0.47
Emissions (tCO_2-eq)	1.79	0.54	0.93	0.56	0.65	0.58
Net emissions (tCO2-eq)	**0.80**	**0.24**	**-0.06**	**-0.03**	**-0.34**	**-0.31**

Displacement of oil in global markets: The response of oil markets to EOR+

The results shown in Table 3 above do not include the impacts of displacement i.e. oil produced from *EOR+* could displace oil that might otherwise have been produced elsewhere. In such a case, the reduction in consumption of a higher carbon intensity crude results in an emissions reduction.

In order for CO_2-EOR to be attractive, a barrel recovered through use of CO_2-EOR must have a lower cost than that produced from competing options (e.g. unconventional resources, deep water). Thus, oil brought to market through the application of CO_2-EOR will have lower supply cost than the marginal barrel. Without a corresponding change in oil demand, this would lead to a reduction in oil prices; however, the response of consumers will be to consume more oil, leading to the establishment of a new equilibrium in the market (Figure 11). EOR practices effectively shift the oil supply cost curve towards to the left: the oil price at which demand and supply are balanced drops from P_0 to P_1, and oil consumption at the lower price increases by ΔQ, clearing the additional available supply. The critical questions are: (1) how much oil production is displaced by CO_2-EOR; (2) how much additional production reusults from CO_2 EOR; and, (3) what is the resulting net impact on CO_2 emissions.

Figure 11 • Impact of *Advanced EOR+* on oil demand

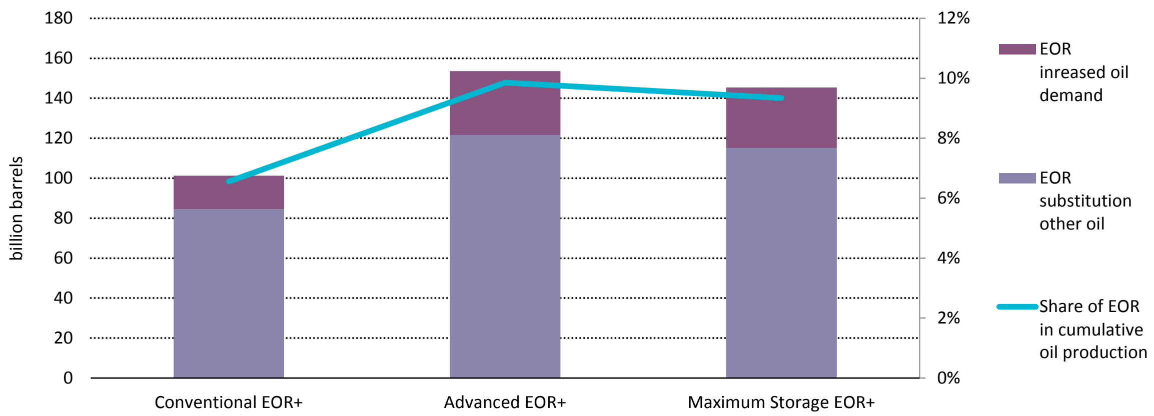


To provide some insights into the first and second questions, we constructed global oil supply curves that incorporate the three CO_2-EOR scenarios. These oil supply curves build on country-level data for resources and costs of the three CO_2-EOR oil production scenarios, as well as resource and economic data for other conventional and unconventional oil categories. They are based on the commercially available Rystad UCube database, which was the basis for the assessment of technical potential presented earlier. The resulting global oil supply cost curves were used to determine a least-cost solution to meet specified oil demand over the time horizon 2013-50.

In this assessment, oil supply is assumed to have to meet annual oil demand as specified in the 6DS for the time period up to 2050. The response of oil demand to price variation is captured such that price signals affect demand more strongly in the long term than in the short term. Correspondingly, oil price elasticity of demand increases in absolute value from 0.1 in the short term to 0.2 in the long term.

Modelling results for the incremental cumulative oil production obtained with the three CO_2-EOR practices show that *Conventional EOR+* could contribute more than 6% of total oil production to 2050 whereas *Advanced EOR+* could contribute up to 10% (Figure 12). However, because of its relatively higher cost, *Maximum Storage EOR+* contributes only 9% – i.e. less than *Advanced EOR+*. Under the above analysis, some 20% of the cumulative oil production realised via *Conventional EOR+* and *Advanced EOR+* would be additional production; the vast majority (80%) would effectively substitute other oil production, which would be displaced from the market.

Figure 12 • Cumulative incremental CO_2-EOR oil production, 2013-50



Estimating the CO_2 emissions savings from the displaced oil is challenging, as it requires knowledge of the emissions associated with its production, transportation, refining, and ultimately use (i.e. combustion) of the refined products. The emissions profile – that is the "well-to-wheel" emissions per barrel – of oil from different sources varies far more than has been assumed in the past. Gordon et al. (2015) recently examined the emissions of 30 different types of crude oil, finding that their associated emissions range from 450 $kgCO_2$-eq/bbl to 820 $kgCO_2$-eq/bbl. The model used in Figure 12 does not have sufficient resolution to capture this variability; hence, we assume a comparable[13] oil is displaced, and then consider the impacts of displacement of higher and lower carbon intensity oils.

The impact of displacement on the economy-wide emission from undertaking *EOR+* are provided in Table 4.[14] This table shows that when displacement is considered, even *Conventional EOR+* can generate an emissions reduction benefit when displacing low CO_2-intensity oil. This emissions reduction benefit of CO_2-EOR persists until the rate of displacement reaches 0.5 (i.e. 1 barrel of oil

[13] "Conventional" crude oil as in Gordon et al., 2015.

[14] We assume the baseline against which we are making a comparison is one in which the equivalent amount of displaced oil is being produced from either a low or high intensity source, and the CO_2 that would otherwise be used in EOR is being stored in a saline aquifer. If we were to assume the CO_2 was emitted in the absence of CO_2-EOR, the benefit accruing to CO_2-EOR would be larger than estimated in Table 4.

from *Conventional EOR+* displaces half a barrel of low-CO_2 intensity oil). The emissions reduction benefit of *Advanced EOR+* and *Maximum Storage EOR+* are relatively large because they result in emissions reductions without considering the benefits of displacement, as shown in Table 3.

Table 4 • Illustrative CO_2 emissions resulting from three *EOR+* practices including combustion of the produced oil and price effects in global oil markets

Scenario	*Conventional EOR+*		*Advanced EOR+*		*Maximum Storage EOR+*	
Functional unit	1 tCO_2 delivered	1 bbl produced	1 tCO_2 delivered	1 bbl produced	1 tCO_2 delivered	1bbl produced
Additional emissions from EOR+ (tCO_2-eq)	0.13	0.04	-0.01	-0.01	-0.07	-0.06
Displaced emissions from other oil (tCO_2-eq)	-0.76	-0.23	-0.72	-0.43	-0.72	-0.65
Net emissions (tCO_2-eq)	**-0.63**	**-0.19**	**-0.73**	**-0.44**	**-0.79**	**-0.71**

Varying the life-cycle emissions intensity of the displaced oil has a significant impact on the estimate of the emissions reductions that accrue from *EOR+* activities. In a case where an oil with the lowest emissions intensity reported by Gordon et al. (2015) is displaced, the emissions reduction benefit of *Conventional EOR+* is reduced to -0.47 tCO_2/tCO_2 delivered; however, in the case where the highest emissions intensity oil is displaced, the benefit of *Conventional EOR+* increases to -1.50 tCO_2/tCO_2 delivered. The variation in the emissions reduction benefit with displaced oil intensity is smaller for the *Advanced EOR+* and *Maximum Storage EOR+* cases because they are less efficient from an oil production perspective – i.e. they have larger net utilisation of CO_2.

As demonstrated throughout this section, understanding the net CO_2 emissions benefit of EOR on both project level and globally is a complex task. It requires thorough analysis and clear decisions regarding the included elements ("project boundaries"). However, the above results clearly show that *EOR+* can generate an emissions reduction benefit.

Overcoming barriers to EOR+

Key points

CO_2-EOR is currently not widely used for storage, as there is no business case for storage. In absence of a significant carbon price, a business case could, however, be created through relevant incentive policy frameworks in the short term.

Policies to ensure the permanent retention of CO_2 underground and the long-term monitoring and stewardship must also be implemented.

Despite the large technical potential of CO_2-EOR, today it only contributes about 0.35% of global oil production, mainly from a growing number of US projects. Thus, it is not clear that CO_2-EOR is attractive for oil production outside the United States and, it is safe to say that, unless it becomes attractive, little CO_2 will be stored through CO_2-EOR. This is of particular significance because, as the US experience demonstrates, CO_2-EOR can make early, large-scale capture projects viable, which contributes to reductions in capture costs and benefits CCS in the longer term. Thus, governments that want to see and harness the potential of *EOR+* must, in the first instance, understand how to drive wider use of CO_2-EOR.

If CO_2-EOR is an attractive proposition in itself, requirements for storage-focused activities are then worth considering. Today, CO_2-EOR projects do not undertake such activities, because there is generally no driver to do so. This means that governments need also to establish a framework to promote effective CO_2 storage through CO_2-EOR, i.e. *EOR+*. Once *EOR+* is being employed as a storage option, increases in consumption of CO_2 at the project level can improve the potential for CO_2-EOR to contribute to emissions reductions.

There are three types of barriers facing greater *EOR+*:

- expanding the use of EOR in the first place
- subsequently incentivising the adoption of business practices to “store” CO_2 consistent with the requirements of the climate change mitigation objectives
- injecting more CO_2 as part of the EOR extraction process.

The following sections examine these issues and discuss potential policies that governments could explore further.

Barriers to wider use of CO_2-EOR

While there is no definitive history of CO_2-EOR that explores the combination of factors that led to the genesis of CO_2-EOR in the United States, it is safe to say that these factors have not combined in a way to drive CO_2-EOR development elsewhere. What is clear, however, is that US research and development into CO_2-EOR, beginning in the 1950s, and the subsequent growth of the industry starting in 1970s, was largely undertaken by commercial entities. These companies were seeking to bolster declining reserves in what were, even then, mature fields in the Permian basin.

Today, as in the past, the fundamental driver for CO_2-EOR clearly remains increasing oil recovery from mature assets. The historical development of CO_2-EOR shows that it can be a profitable activity at oil prices in the range of USD 40/bbl (in 2015 real dollars) and the growing number of projects today shows that it remains an attractive investment option. There appear, however, to be several reasons why the flow of investment into CO_2-EOR projects is not larger:

1. CO_2-EOR requires a large capital investment late in the life of a field.
2. While CO_2-EOR increases recovery from a field, the increase is captured over a long period of time and, thus, its NPV is diminished.
3. While CO_2-EOR technology is well understood, in principle, its application is reservoir specific and requires field pilot tests to optimise.

The first factor may further be amplified when offshore cases are considered, as modifications to production platforms can often be very costly and are difficult to undertake while in service. Combined, these factors mean that, while an operator may expect a CO_2-EOR project to be profitable, it may not be an attractive investment in comparison to other options in a portfolio (ARI, 2011; IEA, 2012a). In addition, lack of CO_2 transport infrastructure may prove a hurdle for starting or expanding CO_2-EOR operation.

Fundamentally, governments have two options to boost the attractiveness of CO_2-EOR: provide incentives for CO_2-EOR developments, or implement policies that make competing investment options less attractive. Practically, the first option – that is, providing incentives – may be more attractive option than the latter. However, it is important to recognise that climate policy could accomplish the second option, as it would likely shift oil and gas investment towards projects with lower upstream emissions. Thus, even without considering the impacts of climate policy on availability and price of CO_2 for use in EOR, CO_2-EOR could stand to benefit from climate policy. The optimal policy to encourage CO_2-EOR is likely to be a combination of the two options.

Most commonly, incentives for oil and gas production take the form of reductions in the government take for specified activities.[15] The net impact of such incentives would be to increase the after-tax present value of project revenues. An option with a similar impact is the provision of production tax credits. Either of these options could be tied to requirements for storage-focused activities.

Another approach could be to provide investment tax credits that offset the capital expenditures required for CO_2-EOR projects. As with reductions in government take or production tax credits, they can also be linked to requirements for storage-focused activities. Investment tax credits could also be used specifically to support pilot projects where the level of risk is relatively high, and the production potential small. Of course, when designing any incentive scheme it is important to carefully craft project eligibility criteria, regularly review the scheme to ensure it remains fit for purpose, and clearly identify limits to the scheme after which it will no longer apply.

In addition to these three factors, relatively limited access to suitable supplies of CO_2 presents a substantial barrier to further CO_2-EOR (ARI, 2011). This issue particularly an issue in the regions with large technical potential identified here. Even in the US, this has been highlighted as a barrier to more rapid expansion of CO_2 (e.g. NETL, 2011; NEORI, 2012) – although, in this case, it might be more precise to say that the current supply of CO_2 matches the price that CO_2-EOR operators are willing to pay.

Increasing the supply of CO_2 for EOR can be facilitated by support for CO_2 capture from anthropogenic sources, as well as policies to encourage development of pipeline infrastructure. Support mechanisms for CO_2 capture should be tailored to the stage of technology development,

[15] For example, the US Federal Government has provided tax incentives for CO_2-EOR operators; see, for example, Dooley et. al., 2010.

and placed in an adaptive framework so that, over time the incentives remain fit for purpose (IEA, 2012b).

It is critical to recognise that not all capture technologies are at the same stage of development in all applications: for example, some of the original CO_2 sources for EOR projects in the United States were from gas processing, whereas only in 2014 did the first power plant equipped with capture come on line. For capture from power generation, the initial technology development objectives call for economic instruments specifically designed to provide support for learning and early deployment (IEA, 2012b). Capital subsidies, loan guarantees and operating subsidies are examples of instruments known to effective at this stage that can be geared towards funding new capture projects.

Framework to ensure effective storage of CO_2 through EOR

Laws and regulations are needed to encourage the safe and effective design and operation of CO_2 storage options. For CO_2 stored through EOR to qualify as "not emitted" – and thus gain the benefits of climate policy – the operator must comply with regulations to ensure that the CO_2 is retained in the reservoir. Similarly, regulations to ensure CO_2 storage is undertaken in a way that protects human health and the environment should apply equally to CO_2-EOR.

As noted earlier, to qualify as CO_2 storage, operators will have to adjust the design and operations of a CO_2-EOR project before, during and following CO_2-injection:

- Additional site characterisation to collect information on overlying cap-rock and geological formations, as well as abandoned wellbores, to assess the potential for leakage of CO_2 from the reservoir.
- Additional measurement of venting and fugitive emissions from surface processing equipment.
- Monitoring and enhanced field surveillance aimed at identifying and, if necessary, estimating leakage rates from the site to assess whether the reservoir behaves as anticipated.
- Changes to abandonment processes that help guarantee long-term containment of injected CO_2, such as plugging and removal of the uppermost components of wells so they can withstand the corrosive effects of CO_2-water mixtures.

This being said, however, few regulatory frameworks have been developed that explicitly recognise the important differences between storage through CO_2-EOR and in other geological reservoirs. These differences are both positive, such as a reduction the area of elevated pressure and the presence of a demonstrated seal, and negative, as the seal may have geo-mechanical damage and there are many existing wellbores (Hill et al., 2013).

At a minimum, regulations applied to CO_2-EOR should ensure that:

- CO_2-EOR operators undertake the necessary up-front site characterisation, modelling, and risk assessment to satisfy regulatory authorities that the storage project (i.e. the reservoir and wells) will effectively retain stored CO_2.
- Emissions from surface equipment, in particular venting and fugitive emissions, are monitored, measured, and reported to ensure that the amount of CO_2 stored can be accurately calculated.
- Monitoring and enhanced field surveillance are undertaken to: assess whether the reservoir behaves as anticipated and allow risk assessments to be updated; and, identify and, if necessary, estimate leakage rates from the site to the atmosphere.

- Site closure practices support long-term containment of injected CO_2, in particular, those relating to plugging and abandonment of wells so they can withstand the corrosive effects of CO_2-water mixtures over the long term.
- Long-term monitoring and stewardship are carried out according to the relevant body of laws and regulations.
- In addition, governments should establish the relevant processes by which a CO_2-EOR project can transition into a pure storage project upon depletion of the reservoir. For example, the US Environmental Protection Agency (EPA) has recently issued draft guidance on the transition of a well permitted for use in CO_2-EOR (i.e. Class II) to well permit for geologic CO_2-storage (i.e. Class VI) (EPA, 2013).

It is also important to recognise that these storage-focused activities may depend on relatively new technologies and are not commonly undertaken. For example, while CO_2-EOR projects in the United States have created ample experience with CO_2 transport and injection, experience with decommissioning is lacking. Thus, funding research and development, as well as field trials for these technologies and activities is an appropriate government intervention. Such funding should support dedicated testing to de-risk and build experience with novel approaches to modelling and risk assessment, fugitive emissions monitoring technologies, subsurface monitoring and field surveillance, and field decommissioning and closure for long-term storage. Funding in these areas could have benefits for all types of geologic storage.

Box 4 • Key actions from the IEA CCS Roadmap

In its 2013 *CCS Roadmap*, the IEA sets out key actions needed to confirm the practicability of CCS as a large-scale CO_2 abatement tool and to set it on the required deployment pathway. Many of the Roadmap's recommendations concern the critically important areas of providing financial incentives and other policy drivers, as well as ensuring the safety and timely development of CO_2 storage. Thus, the seven key actions identified are equally relevant to *EOR+*:

1. Introduce financial support mechanisms for demonstration and early deployment.

2. Develop laws and regulations that effectively require new-build power capacity to be CCS-ready.

3. Significantly increase efforts to improve understanding among the public and stakeholders of CCS technology.

4. Implement policies that encourage storage exploration, characterisation and development for CCS projects.

5. Reduce the cost of electricity from power plants equipped with capture through continued technology development.

6. Prove capture systems at pilot scale in industrial applications.

7. Encourage efficient development of CO_2 transport infrastructure.

In addition, the Roadmap provides one specific action regarding *EOR+* (Action 9):

9. Where CO_2-EOR is being undertaken as part of long-term geologic storage operations, ensure that it is conducted under appropriate, storage-specific regulatory regimes.

In addition to the appropriate regulatory requirements for storage through CO_2-EOR, governments may also need to consider other legal issues that could limit the potential for storage. Generally, these issues stem from the different models of regulation for CO_2-storage and

CO_2-EOR; the former being focused on disposal of a waste and, the latter, on resource recovery (Marston, 2013). Thus, for example, where hydrocarbon recovery is given primacy the effective sterilisation of the resource remaining in place after cessation of oil production may cause legal complications. This situation may be particularly vexing in the US, where onshore mineral and storage rights are, for the most part, privately held and separate (Marston, 2013). These sorts of legal issues are inherently jurisdiction-specific, as are the potential solutions.

Barriers to the use of more CO_2 per barrel of oil

As the illustrative economic analysis has hopefully demonstrated, declining supply costs of CO_2 or – *ceteris paribus* – increasing prices of oil can lead to increased consumption of CO_2 by an EOR operator and an expanded storage resource base. However, there is a tension between those who view CO_2-EOR as a means of supporting capture technology demonstrations, which would benefit from high prices for CO_2 sold into EOR markets, and those who would like to see increased use of CO_2 for EOR, which would result from lower CO_2 prices.

In the United States, recent market prices of CO_2 for EOR, while sufficient to drive capture from relatively high concentration sources, are generally insufficient to cover the first-of-a-kind capture costs in power generation. Additionally, the volatility of oil-linked CO_2 prices, flexibility provisions, and duration of typical CO_2 supply contracts may provide a disincentive for investors in capture plants. While alternatives to conventional supply contracts are emerging in the United States (e.g. joint ventures such as Petra Nova), a recent US analysis (NEORI, 2012) recommended introducing a federal production tax credit for CO_2 capture and transport.

The way in which incentives could be structured to both encourage increased use of CO_2 for EOR and capture from anthropogenic sources, particularly outside the US, is an area where additional assessments are required.

Conclusions

Injecting CO_2 into oil reservoirs to enhance oil recovery is a well-known commercial practice. While CO_2-EOR is a technically mature technology to enhance oil production, applying it to control CO_2 emissions requires a major shift in business practices and government incentives. Adapting CO_2-EOR for CO_2 storage in fact represents an early and unique opportunity for kick-starting CCS deployment. Past experience in United States and a few other countries is valuable to understand the drivers behind conventional EOR, but it provides incomplete guidance for extending CO_2-EOR into the field of climate change mitigation.

There are seven policy-relevant conclusions that can be drawn from the analysis presented in this report:

1. With novel practices it is possible to turn today's EOR from a pure petroleum production tool to a means of storing CO_2 in large quantities – namely *EOR+*. Advancing to a business model in which long-term CO_2 storage is a revenue stream requires a fundamental shift in thinking and operations. It requires that operators re-consider reservoir management practices and operational choices that explicitly incorporate both increased oil production and storing of CO_2 as joint business objectives. At present, no site is pursuing this dual objective.
2. Adding storage-related activities to CO_2-EOR inherent in *EOR+* increases the costs of undertaking CO_2-EOR; the offsetting of these costs must be driven by climate factors such as a price on carbon or a regulatory or permitting requirement. Hence this requires a change in incentives and support from government – one in which storage of CO_2 generates a value for the operator.
3. Co-exploiting CO_2-EOR for both CO_2 storage and increased oil production could deliver NPVs that exceed those for conventional CO_2-EOR projects. Across a variety of CO_2 and oil price trajectories, a scenario that uses more CO_2 while recovering more oil (*Advanced EOR+*) is preferred over scenarios that recover less oil (*Conventional EOR+*) or store more CO_2 (*Maximum Storage*). Hence under realistic oil and carbon price assumptions, fields that recover more oil AND provide long-term CO_2 storage can be more profitable. All other things being equal, lower cost to acquire CO_2 (i.e. lower supply prices) will lead to additional use of CO_2, as will higher oil prices.
4. The technical potential for CO_2 storage through *EOR+* is large in relation to the potential demand for CO_2 storage, regardless of the scenario considered. The potential ranges from 60 $GtCO_2$ to 360 $GtCO_2$ globally in the next 50 years, i.e. from 50% to more than three times the amount of total CO_2 storage required under the IEA 2DS scenario through 2050. Similarly, the volumes of oil that could be produced are substantial, up to 375 billion barrels over the next 50 years, which could both contribute to government revenues and impact global oil markets.
5. The technical potential of *EOR+* is not evenly distributed: four regions outside the United States account for 90% of the potential, much of which is located far from CO_2 sources. In addition, one-third of the potential is located offshore.
6. Widespread use of *EOR+* appears likely to result in some additional oil consumption. However, high-level estimated indicate that while a small proportion of oil produced through *EOR+* would be additional, most of *EOR+* oil production would substitute oil produced through other means without CO_2 injection and storage. This substitution can result in net reductions in emissions given the incremental storage being generated through *EOR+* practices. It is however critical that appropriate in-depth life-cycle analyses be performed to assess both project-level and cumulative net impact.

7. To stimulate use of CO_2-EOR to achieve the benefits of CO_2 storage and greater oil extraction, governments could consider creating supportive policy frameworks to drive first projects. Equally, a framework of laws and regulations is needed to encourage the safe and effective design and operation of CO_2 storage options. For CO_2 stored through *EOR+* to qualify as "not emitted" – and thus gain the benefits of climate policy – the operator must comply with regulations to ensure that the CO_2 is retained in the reservoir.

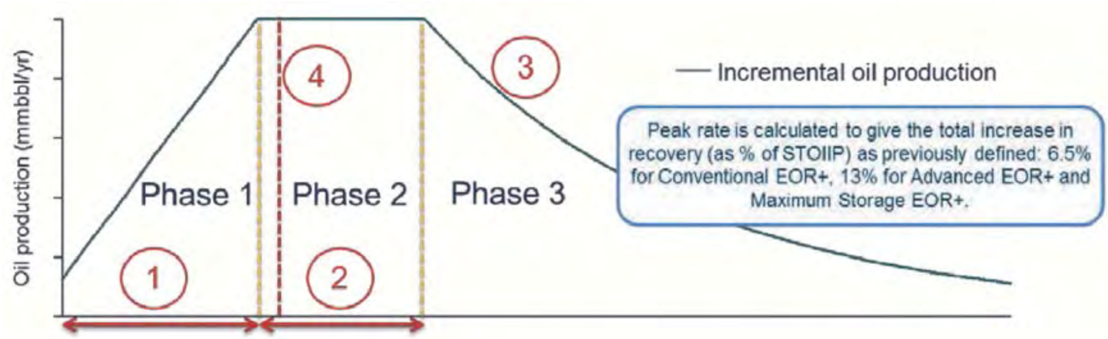
Annex 1. Technical aspects of a hypothetical CO_2-EOR+ case study

The hypothetical field used for the evaluation contains 1 Bbbl of OOIP (on a stock-tank basis) prior to the start of production. The economic analysis is based on simplified oil production and CO_2 injection profiles that might be representative of different CO_2-EOR practices. The cost accounting does not include the initial capital costs of production facilities installed before starting CO_2-EOR, which are assumed to be inherited at zero cost. In this hypothetical case, CO_2-EOR flooding commences in 2022 when the remaining oil falls to 30% of recoverable reserves. CO_2 recycling is assumed to begin in 2028. This case assumes an emissions pathway consistent with the ETP 2DS; the evolution of oil and CO_2 prices reflect those assumed in *ETP 2012.*

Production and injection profiles

We assume an oil production profile for the hypothetical project has three distinct phases (Figure 13). In Phase 1, new CO_2 injection wells are drilled and put in operation along with the supporting injection and production infrastructure in stages, which results in increased production. In Phase 2, incremental oil production reaches and remains at a plateau, the length of which is determined by injection rates and the rate of pattern build out in the first phase. By this time, enough CO_2 has been injected to induce "breakthrough" and reach the oil production wells. This breakthrough occurs earlier for *Conventional EOR+* flooding than for the *Advanced EOR+* and *Maximum Storage* practices as a result of design choices and operating procedures specific to the latter practices. In Phase 3, incremental oil production declines exponentially with an increasing fraction of CO_2 being produced alongside oil.

Figure 13 • Schematic production profile used for analysis



	Assessment	Unit	Low	Base	High
1	Time to plateau	years	10	20	30
2	Time at plateau	years	20	30	80
3	Decline rate after plateau	%	375	1125	1875

			Conventional EOR +	Advanced EOR+ and Maximum Storage EOR+
4	Peak incremental production	% of STOOIP	0.52	1.04

The oil production profile determines the volume of CO_2 that needs to be purchased and stored. Over time, the need to purchase "new" CO_2 decreases in direct proportion to oil production: more CO_2 is available through recycling as oil production declines. The stored volume is calculated by multiplying incremental oil production with the CO_2 utilisation factors characterising the CO_2-EOR scenarios described (see Table 1, p. 16). Thus, the analysis assumes that CO_2 purchase rates follow an exponential decline curve reflecting that of oil production.

Costs for each of these functions are based on the assumption that about half (by value) of the existing separation equipment is replaced as necessary and new equipment is added to handle CO_2 (Tables 5a and 5b). In practice, the costs for these activities may vary depending on the past history of the oil field and, the level of hydrocarbon recovery desired from the recycle gas, and options for produced water disposal. Of course, estimated costs are only approximate, as they are based on a very low level of project definition.

Table 5a • Key cost assumptions: Capital expenditure

Activity	Unit	Low	Base	High	Notes
CO_2 injection	USD/tCO_2pa	10	20	30	
Injection wells	USD million	20	30	80	
Oil / gas / water separation	USD/bbl/d	375	1 125	1 875	30-50% of processing equipment replaced at 1.25 original cost as expensive materials Total liquid flow (oil + water)
CO_2 / gas separation	USD/scf/d	0.5	2.25	4.0	Total gas flow (CO_2 + gas)
CO_2 recycling compression	USD/W	1	1.5	2	Cost of compression to inlet stream

Table 5b • Key cost assumptions: Operational expenditure

Activity	Unit	Low	Base	High	Notes
CO_2 injection	USD/tCO_2				Assumed to be negligible
Injection wells	USD million pa	0.8	1.5	2.5	4% of well CAPEX
Oil / gas / water separation	USD/bbl	1	2	3	Based on previous conventional oil projects. Variable OPEX based on throughput
CO_2 recycling and compression	USD/tCO_2		20		
CO_2 recycling and compression	tCO_2/bbl		0.6		
Produced water cost	USD/1 000 gal	20	40	70	
Monitoring *EOR+*	USD million pa	1.7	2	2.5	Source: US EPA analysis
Monitoring EOR	USD pa		2 500		Source: US EPA analysis

Data in Tables 5a and 5b can then be used to calculate capital and operating costs for the three CO_2-EOR scenarios considered (Figures 14 and 15). Figure 15 also provides information on the increase in OPEX with time.

This analysis finds that injecting more CO_2 for storage drives up both capital and operating costs, even before considering the purchase of CO_2. In the hypothetical case, the capital cost increase of moving from *Conventional EOR+* to *Advanced EOR+* is roughly 55%. Moving from Conventional EOR+ to *Maximum Storage*, the capital cost doubles. These additional costs are almost exclusively due to the need for additional wells – or, *ceteris paribus*, more complex and expensive wells – and associated maintenance. To a lesser extent, CO_2 recycling after CO_2 breakthrough also increases capital expenditure.

Figure 14 • Elements of capital costs for different CO_2-EOR scenarios

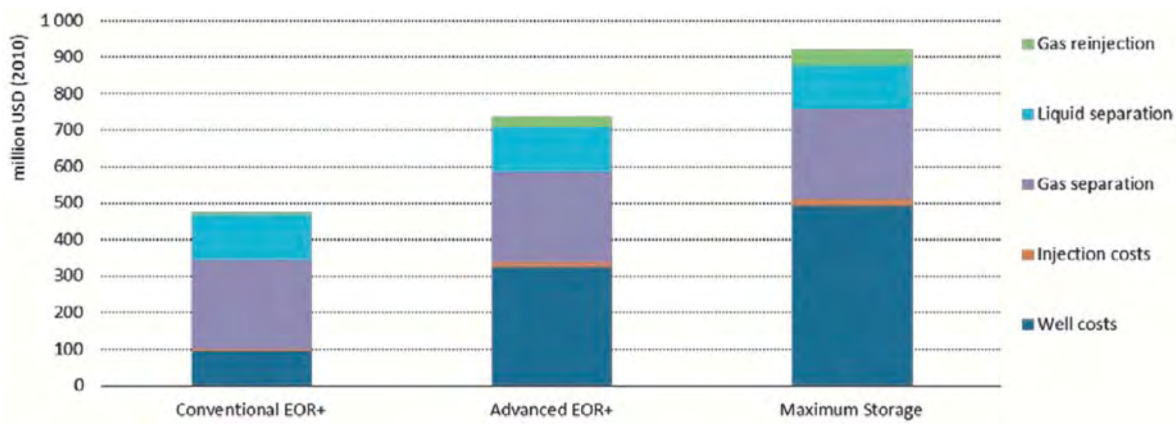
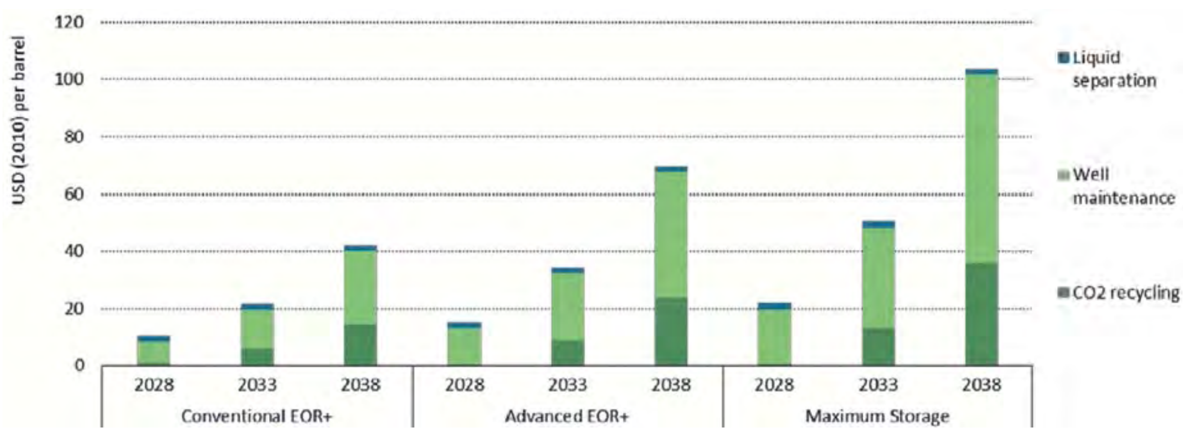


Figure 15 • Change of incremental project operating cost; CO_2 recycling as of 2028



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Acronyms, abbreviations and units of measure

Acronyms and abbreviations

2DS	2-Degree Scenario (*ETP*)
4DS	4-Degree Scenario (*ETP*)
6DS	6-Degree Scenario (*ETP*)
CAPEX	capital expenditures
CCS	carbon capture and storage
°C	degree Celsius
CO_2	carbon dioxide
CO_2-EOR	carbon dioxide for enhanced oil recovery
EOR	enhanced oil recovery
ETP	*Energy Technology Perspectives*
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle
LNG	liquefied natural gas
MMP	minimum miscibility pressure
MMV	monitoring, measuring and verification
NPV	net present value
OOIP	original oil in place
OPEX	operational expenditures
STOOIP	stock-tank original oil in place
WAG	water-alternating-gas (process)
USD	United States dollar

Units of measure

/d	per day
/yr	per year
bbl	barrels of oil
Bbbl	billion barrels of oil
gal	gallons
Gt	gigatonne
$GtCO_2$	gigatonnes of carbon dioxide
kg	kilogramme
Mcf	thousand standard cubic feet
Mt	million tonnes (megatonne)
$MtCO_2$	million tonnes of carbon dioxide
MW	megawatt
pa	per annum
t	tonne
tCO_2	tonnes of carbon dioxide
tCO_2-eq	tonnes of carbon dioxide equivalent
W	watt

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