Carbon Capture Use & Storage (CCUS)

Potential of Carbon Dioxide Reuse in Enhanced Oil Recovery & Industrial Applications

CCS is the single most important technology in the International Energy Agency's 2DS scenario, designed to attain the 2°C climate goal: CCS contributes one-sixth - or 7.8 GtCO2 - of CO2 emissions reductions required in 2050, and one-fifth - or 123 GtCO2 - of the cumulative emissions reductions between 2015 and 2050. If CCS were not available, the investment for reaching the climate target would increase by a further 40%, with an extra cost of US$ 2 trillion [IEA 2012b]. In 2013, the IEA warned that "progress [in CCS] is far too slow to achieve the widespread commercial deployment" *[IEA 2013c]. CCS has not delivered in the EU as well, prompting CCS rapporteur Chris Davies to demand a restart of EU CCS policy. The bulk of CCS investments to date has been in projects that utilise CO2 as a resource, offsetting some of the costs that come with CCS. Thus, venues that use and store CO2 are gaining importance.*

1. The dimension of CO2 Reuse

While Carbon Capture and Storage (CCS) treats CO2 as a waste product that needs to be costly stored away, CO2 Reuse, running under the umbrella term **Carbon Capture & Use** (CCU), transforms CO2 into a resource or commodity. Commercial utilisation of CO2 is considered a possible mitigation option, complementary to geologic storage of CO2 (CCS).

At present, **110-120 Megatons of CO2 p.a.** (MtCO2pa) are sold commercially for a diverse portfolio of applications [Fig. 1]. CO2 is used as a chemical solvent in decaffeination and winemaking, for the carbonation of soft drinks, and for modified atmosphere packing (MAP) in the food industry. Smaller amounts of CO2 are used in dry-cleaning, fire-protection, for the manufacture of fire-protective insulation materials and as a nutrient for greenhouse vegetables. These applications will remain small scale, taking up no more than 15-20 MtCO2pa.

Mature large scale applications to date include manufacture of fertilisers (UREA) and enhanced oil recovery (EOR). UREA production takes up 30 MtCO2pa. The largest single use of CO2 is in enhanced oil recovery, which consumes 70-75 MtCO2pa, and counting. While the UREA CO2 demand is limited to some 100 MtCO2pa, the EOR market could take up well in excess of 600 MtCO2pa [see Fig. 3].

Fig. 1: Existing applications for CO2 Reuse

Enhanced Oil Recovery	Enhanced Gas Recovery
Urea Fertiliser	Horticulture
Food Processing	Food Preservation
Pharmaceuticals	Fire Suppression
Beverage Carbonation	Decaffeination

Source: GCCSI 2011

In addition, there is a number of emerging uses that are still small scale and require extensive research & development, before they reach technical maturity [Fig. 4]. CO2 might serve as a **chemical feedstock** for the production of carbon based polymers or polyurethanes, or as a **nu-**

trient for algae cultivation: Methanol from algae can be used as a primary product for chemicals or refined into fuel for the transport sector. Other uses include enhanced coal bed methane (ECBM), enhanced geothermal systems (EGS), concrete curing, and renewable methanol. Mineral carbonation provides for a specific case, since it uses CO2 neither as a resource nor an intermediate, but is rather a permanent storage solution and alternative or complement to CCS.

CO2 reuse applications may be distinguished whether they **permanently isolate CO2** from the atmosphere (CCUS) or merely recycle CO2 streams (CCU) [Fig. 2]. Non-permanent applications do not assist in climate change mitigation, since they re-release the CO2 back into the atmosphere at the end of their life cycle. Fuels from renewable methanol offer some abatement potential, if substituting fossil fuels and using CO2 from biogenic sources as a feedstock.

Fig. 2: Permanent (CCUS) and non-permanent (CCU) pathways for CO2 Reuse

	Permanent	Not Permanent
Captured CO_2	EOR ECBM EGS Bauxit Residue	Urea Polymers RES Methanol Formic Acid
Dilute CO_2 Flue Gas	ECBM Mineral Carbonation Conrete Curing	Algae Cultivation

Source: GCCSI 2011

The main challenge is scale: *"Given today's uses for CO2, the future potential of CO2 demand is immaterial when compared to the total potential of CO2 supply from large point sources."* [IEA 2013b]. GCCSI 2011 shortlists CCU applications with a substantial demand for CO2 (> 30 MtCO2pa) in the future. The number ranges reveal substantial uncertainties over future potentials; and not all of these applications actually assist in carbon mitigation. Figure 3 lists potentials, permanence and carbon mitigation levels, expressed as the potential of CO2 reduction that comes with the technology (CO2 avoided per CO2 used).

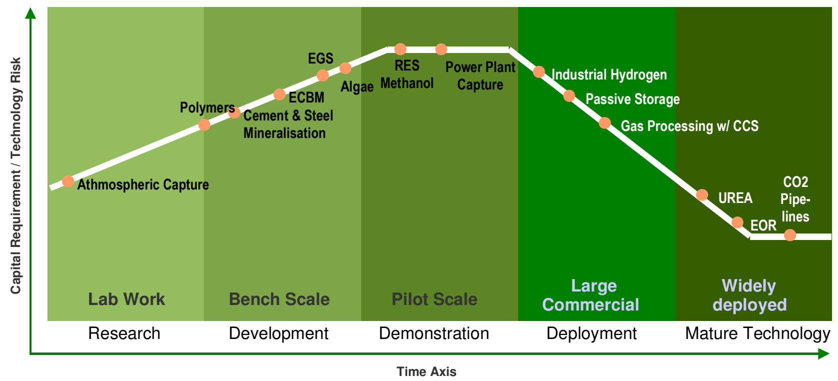
Fig. 3: CO2 Demand and Carbon Mitigation Potential of shortlisted technologies

Existing Uses	Current CO2 Demand (Mtpa)	Future CO2 Demand (Mtpa)	Permanent	Carbon Mitigation Potential
Enhanced Oil Recovery (EOR)	75 to 300	> 600	yes	40 to 129% Median: 51%
UREA Yield Boosting	30 to 70	70 to 110	no	no
Food Treatment	ca. 18	ca. 30	no	no
Emerging Uses				
Enhanced Coal Bed Methane		30 to 300	yes	56%
Enhanced geothermal systems		5 to 30	yes	42%
Polymer Processing		< 30	no	vs. Traditional
Algae Cultivation		> 300	no	58%
Mineralisation		unlimited	yes	68%
CO2 Concrete Curing		30 to 300	yes	vs. Traditional
Liquid Fuels				
Renewable Methanol		> 300	no	biogenic CO2
Formic Acid		> 300	no	no

Sources: GCCSI 2011; DOE 2012; IPCC 2005; IAE 2013b

Many applications are yet immature and require years of research & development. Some come with **huge energy debts**, like renewable methanol or mineralisation, and seem feasible only under excess renewable energy scenarios. Algae cultivation and mineralisation occupy significant amounts of land. Most emerging uses come with high technology risks and capital requirements. In the CCU portfolio, only UREA yield boosting and enhanced oil recovery may be considered mature technologies, with known cost characteristics, capital requirements and moderate technological risks [Fig. 4].

Fig. 4: Maturity and Investment Risk Curve



Source: Inagendo Update of SBC 2011, GCCSI 2011, CFLCF 2011

2. Mature CCU Technologies

2.1 Enhanced oil recovery (EOR)

2.1.1. Definition and Scope

Contrary to widespread perception, oil fields are no underground caverns “filled” with oil. The oil is rather contained in porous geologic formations - limestone, dolomite, and sandstone. **Primary recovery**, using natural reservoir pressure, typically releases 10 to 15 percent of the Original Oil in Place (OOIP), leaving 85 to 90 percent of the oil trapped in the underground.

Second phase recovery involves the injection of fluids, typically water or hot water, to repressure the well and extract an additional 8 to 28 percent of the remaining oil [API 2007; ARI 2010]. Water flooding has been the technique applied in the North Sea Graben (NSG) oil fields of Norway and the United Kingdom since 1979. NSG light oil lends itself to water flooding, eventually releasing about 40 percent of the OOIP [SCCS 2009, DIW 2013].

Since water does not mix with oil, 57 to 82 percent of the OOIP yet remain unrecovered. Starting in the 1970s, exploration companies deployed **third phase recovery** techniques (*enhanced oil recovery)*, to extend lifetime and yield of the fields. 3rd phase techniques seek to alter the physical commodity of the remaining oil, such as viscosity. They involve low saline water, polymers, surfactants (surface active agents), microbials, nanoparticles, and hot steam [1]. European EOR projects in Emlichheim/Germany and Schoonebeek/The Netherlands utilise hot steam of 350°C to enhance oil production; five projects with hydrocarbon injection are underway in the North Sea Graben fields of UK and Norway. Bockstedt/Germany intends to use bio polymers to increase oil viscosity [Koottungal 2012]. To date there are no CO2 EOR activities in the NSG.

[1] For an overview of EOR techniques and fluids see Alvarado 2010

Among concurring EOR techniques, CO2 EOR has become the preferred EOR process globally: At high pressure and reservoir temperature CO2 mixes with the oil to form a low viscosity, low surface tension fluid, thus causing the oil to flow more freely *(Miscible CO2)*. The CO2 mixed with the incremental oil is separated and re-injected. As a side effect, 96 to 100 percent of the CO2 will eventually stay in the reservoir, providing for **incidental geologic storage of CO2** [GCCSI 2013b]. Due to its chemical properties, CO2 is superior to water-flooding: CO2 may invade zones not previously invaded by water, releasing 53 to 82 percent more incremental oil than best-case water flood techniques [API 2007; Melzer 2012][Fig. 5].

Fig. 5: Incremental Oil Recovery by Recovery Mechanism

Stage	Technology / Fluids	OOIP Recovery (in % of OOIP)
Primary	Natural Reservoir Pressure	10 - 15 %
Secondary	Repressure Fluids (Water flooding, Hot Water, Hydrocarbons)	8 - 28 %
Third	Miscible CO2 EOR, Hot Steam, Polymers, Microbial	8 - 23 %
Remaining OOIP		74 - 36 %

Sources: API 2007, ARI 2011

The CO2 EOR technology was patented to Atlantic Refining Company in 1952. In 1972, the first commercial CO2 EOR project was initiated at SACROC Unit of Kelly-Snyder field in the Permian Basin [2]. CO2 for the first projects came from natural gas processing facilities. In the 1980s, the construction of CO2 pipelines - connecting natural CO2 source domes in New Mexico and Colorado to wells in Texas - opened up significant amounts of inexpensive CO2 and jump-started wide deployment of CO2 EOR. This sparked a 3,000 mile Texas-wide CO2 network, with hubs and spokes that allow for low-cost extensions "within striking distance" (up to 200km), providing for **significant economies of scale**. As of 2013, 70 MtCO2pa are used in **126 CO2 EOR projects** in the USA, with CO2 pipelines extending 4,000 miles and cumulated CO2 net injections amounted to 800-900 MtCO2 [Fig. 6]. 68 EOR projects are amassed in the Permian Basin, accounting for two thirds of the world oil production from EOR [ARI 2010].

Fig. 6: EOR Projects, CO2 Sources and Pipelines in the US (2010)

Source: NEORI 2012, ARI 2010

In 2012, CO2 EOR produced 309,000 bbl/day and accounted for 5 percent of US crude oil production [Koottungal 2012, USCSC 2012]. A third of the CO2 originates from **anthropogenic**

[2] SACROC is still operative, with an enhanced oil production of 26.530 bbl/ day

sources, with natural gas processing providing two thirds [Fig. 7]. It should be noted that CO2 from anthropogenic sources (23.5 MtCO2pa) compares to 1.3 percent of the annual power plant CO2 emissions in the US, which amount to 2 GtCO2pa.

Fig. 7: Source of CO2 for EOR in the US

Storage Site	Source Type	CO2 Supply (Mtpa) Natural CO2	Anthropogenic CO2	Total CO2
Texas Utah Oklahoma New Mexico	Geologic Fertilizer Gas Processing	30.0	11.4	41.4
Colorado Kansas Wyoming	Gas Processing		8.0	8.0
Mississippi Louisiana	Geologic	17.0		17.0
Oklahoma	Fertilizer		1.0	1.0
Michigan	Ammonia Plant		0.1	0.1
Saskatchewan	Coal Gasification		3,0	0,0
Total		**47.0**	**23.5**	**70.5**

Source: Inagendo Update of ARI 2011, based on GCCSI 2013c data

Outside the US, Koottungal 2012 lists six commercial CO2 EOR projects in **Canada**, three in **Brazil** - with a fourth project commencing operations in 2013 [GCCSI 2013cd] -, five in **Trinidad**, and one in **Turkey**. Alvarado 2010 reports CO2 pilot injection at Ivanić Field in **Croatia** and Hungarian pilots at Budafa and Lovvaszi fields. Szank Field in **Hungary** utilised CO2 from a sweetening plant. In **China**, EOR technology is applied in two CCUS projects: Tianjin Dagang CCS Project, a 330 MW power unit, and SINOPEC's CO2 Capture & EOR pilot in the Shengli oil field, with six additional EOR projects underway [Gu 2013, GCCSI 2013cd].

2.1.2 CO2 EOR: Cost Economics

The deployment of CO2 EOR in the US was driven by low drilling costs onshore, availability of cheap CO2, and **tax incentives** at State and Federal level. Tax rates on conventional oil in Texas are at 4.6 percent, with a reduced rate of 1.15 percent for use of anthropogenic CO2. By contrast, oil royalties in Europe (DK, UK, NOR) amount to 33 to 50 percent, in addition to corporate taxes: Overall oil tax in the UK amounts to 81 percent [SCCS 2013; NEORI 2012].

Unlike in offshore operations, where brine for 2nd phase recovery is a free resource, water flooding in onshore environments comes with considerable water costs: In half the CO2 EOR projects, the CO2 cost per barrel of incremental oil – given a 53 to 82 percent **yield superiority** over water-flooding – caused projects to move directly from primary to 3rd phase EOR production, and bypass 2nd phase water-flooding altogether [Koottungal 2012].

In the absence of a carbon price signal for incidental CO2 storage, the **commercial viability** of CO2 EOR has traditionally been a function of CO2 cost and oil price [Fig. 8], weighted off against the amenability for EOR: Amenability is expressed by the EOR recovery efficiency, as the amount of the incremental OOIP that may be redeemed, and the share of CO2 injected per barrel of incremental oil. Incremental recovery is driven by

- the prevalent lithology of the geologic formation - in terms of porosity and permeability,

- the depletion efficiency of second phase recovery, if any, and thus the remaining OOIP, and
- the expectation whether capital costs associated with EOR refurbishment and pipelines might be recovered over the duration of the project.

Since every incremental barrel of oil produced under CO2 EOR is an extra barrel not produced in its absence, CO2 EOR is profitable as long as revenues from incremental oil offset CO2 costs, which are ranging from 33 to 68 percent of total EOR costs [Hill 2011].

Fig. 8: Incremental EOR production depending on CO2 and Oil price

CO2 Lease Gate Costs		Oil Price (US$ per bbl)		
$/metric ton	$/Mcf	$30	$70	$100
$ -	$0.00	13.16%	15.56%	16.07%
$ 15.00	$0.79	11.03%	15.22%	15.92%
$ 30.00	$1.59	5.51%	14.82%	15.69%
$ 45.00	$2.38	2.46%	14.21%	15.50%
$ 60.00	$3.17	0.35%	13.48%	15.28%
$ 75.00	$3.97	0.14%	11.73%	14.73%

Source: ARI 2011

Historical US CO2 contracts have ranged between 8 and 23 US$ per tonne of CO2 (tCO2). The 2010 CO2 cost of Denbury's Gulf project was given at 5.05 US$/bbl [USCSC 2012]. As one tCO2 produces 3.2 to 4.4 barrels of incremental oil, CO2 cost is on average **38 percent** of the price per incremental barrel. CO2 contracts are indexed to the Western Texas Intermediate oil exchange (WTI), but may vary by region. With oil prices in excess of US$100/bbl, ARI 2011 considers CO2 EOR to be economic at **US$ 40-45 per tCO2**. USCSC 2012 cites a range of **US$ 29-58 per tCO2** [USCSC 2012]. This is commensurate with SCCS 2009 calculations for the Scottish North Sea: *"If CO2 is a cost to projects in the £20–£40 ($28–$56) per tonne range, an oil price of US $80–$110 per barrel will be required to break even."*

As the cost of CO2 is the largest cost component of a CO2 EOR project, field operators have traditionally sought to minimise the amount of CO2 injected. On average, 0.23 to 0.35 tCO2 are injected to produce one incremental barrel of oil. If the focus were not on minimising CO2, but on **CO2 sequestration**, CO2 injection might double to 0.64 tCO2/bbl, with additional opportunities for post-operation storage [ARI 2010]. Given a paradigm shift, CO2 EOR might remove significantly larger amounts of CO2 from the atmosphere than indicated by commercial projects. *"For operators to consider carbon storage a part of the business some form of price, tax or policy on carbon will need to be implemented"* [GCCSI 2013b]. To open up greater volumes of CO2, the gap between commercial CO2 price and cost estimations for carbon capture, which are at 59 to 71 US$/tCO2, will need to be closed [USCSC 2012].

2.1.3. CO2 EOR: Facilitating CCS

Storing CO2 in association with EOR can reduce the overall costs, since CCS deployment costs are – at least partially – offset by the value of CO2. Thus, CO2 EOR serves as a **facilitator for CCS**. 14 out of 20 ongoing Large Scale Integrated CCS Projects (LSIP) – or 70 percent – use enhanced oil recovery [Fig. 9] [3]. Out of 44 LSIPs under evaluation, 16 are dedicated to Carbon Storage (CCS), while 19 are EOR projects [see Appendix A for full list]. Newly announced projects 2013 were exclusively targeting EOR [GCCSI 2013cd].

[3] LSIPs are defined to use 400 MtCO2 in industrial processes or 800 MtCO2 in power generation

Fig. 9: Large Scale CO2 EOR Projects under Operation or Construction

Status	Project	Site	Volume CO2 (Mt)	Start Date	Type	Pipeline Length (km)
Operate	Air Products Steam Methane Reformer EOR	USA	1	2013	Hydrogen	101-150
Operate	Century Plant	USA	8.4	2010	Natural Gas	69
Operate	Coffeyville Gasification Plant	USA	1	2013	Fertiliser	112
Operate	Enid Fertilizer CO2 EOR	USA	0.7	1982	Fertiliser	225
Operate	Great Plains Synfuel Plant & Weyburn-Midale	CAN	3	2000	SynGas	315
Operate	Lost Cabin Gas Plant	USA	0.8-1.0	2013	Natural Gas	N/S
Operate	Petrobras Lula Oil Field CCS	BRZ	0.7	2013	Natural gas	On-Site
Operate	Shute Creek Gas Processing Facility	USA	7	1986	Natural Gas	403
Operate	Val Verde Natural Gas Plants	USA	1.3	1972	Natural Gas	132
Execute	Alberta Carbon Trunk Line ("ACTL") with Agrium CO2 Stream	CAN	0.4-0.6	2015	Fertiliser	240
Execute	Alberta Carbon Trunk Line ("ACTL") with North West Sturgeon Refinery CO2 Stream	CAN	1.2-1.4	2016	Oil Refining	240
Execute	Boundary Dam Integrated CCS Demonstration	CAN	1	2014	Power Gen.	100
Execute	Kemper County IGCC	USA	3.5	2014	Power Gen.	75
Execute	Uthmaniyah CO2 EOR Demonstration	Saudi Arabia	0.8	2014	Natural gas	70

Source: GCCSI 2013c [for full list see Appendix A]

Anthropogenic CO2 streams for EOR have been traditionally provided by natural gas processing, synthetic natural gas and ammonia production, as these provide for low-cost CO2. Since 2013, Century Plant is the largest single industrial source CO2 capture facility in the US, with a total capture capacity of 8.4 MtCO2pa. The CO2 is captured from a natural gas processing plant in Texas. A 260 km long pipeline connects the plant to a CO2 hub in Denver City/TX. The CO2 is injected into the Permian delivery system and used for EOR [GCCSI 2013c].

The costs for power plant capture are considerably higher and may – in the absence of a carbon price signal – only be partially offset by EOR: The first two commercial-scale capture projects to supply anthropogenic CO2 from **coal-fired power plants** will commence operations in 2014: Boundary Dam Power Plant (Saskatchewan) is designed to capture 1 MtCO2pa, which is to be injected, via a 100 km pipeline, to sinks in the Williston Basin. The Kemper County IGCC (Mississippi) captures 65-67 percent of the plant's CO2 emissions, accruing to 3.5 MtCO2pa, delivered to injection wells via a 75 km pipeline [GCCSI 2013d].

The dominance of EOR projects in large scale CCS is not alone a factor of offsetting at least part of the CCS cost: EOR gained **considerable political support** of late, since it

a) offers substantial CO2 sequestration potential and – thus - a viable carbon mitigation option,
b) produces large amounts of incremental oil, taking imported oil off the domestic energy bill,
c) thus reducing reliance on foreign resources, and
d) facilitates the deployment of first mover carbon capture and storage projects.

The **US Department of Energy** announced a policy shift from CCS to CCUS, with CO2 EOR as a key to increase US Oil production, while lowering domestic CO2 emissions. The US have refocused their US$ 3 billion CCS development programme to CCUS [NETL 2011].

China included CO2 EOR in its 12th Fifth Year Plan 2011. In 2013, the National Development and Reform Commission (NDRC) issued a note on promoting CCUS pilots. NDRC is China's governmental body responsible for addressing climate change. NDRC Director General Su Wie contended: *"CCS still faces some challenges including the high cost and energy penalty and while costs are likely to come down as we improve our understanding and optimisation of the technology, the utilisation of CO2 for EOR and other industrial purposes will be important to our development pathway"* [4]. All six of China's newly added CCS projects to the GCCSI database are designed to use CO2 EOR [see Annex A].

The **United Kingdom** *"recognise that CO2 Enhanced Oil Recovery (EOR) could play an important role in the development of some CCS projects"* [DECC 2013a]. The UK Oil and Gas Industrial Strategy expects EOR to improve the oil production within the UK by 4 percent over the next 35 years: *"DECC believe that there is significant miscible gas EOR potential remaining in the North Sea, both for hydrocarbon gas and CO2 EOR, if suitable supplies of injection gas can be identified"* [DECC 2013b].

2.1.4. CO2 EOR: US & Global Potentials

CO2 EOR potential is a function of wells amenable to EOR and low-cost CO2 sources "in striking distance" to injection wells. Most EOR projects to date are within a 250 km diameter from CO2 sources, but diameters of 750-800 km remain an economic option, if pipeline costs might be redeemed. The availability of anthropogenic CO2 is key to explore EOR potential.

For the US, NETL 2011 projects that oil production from CO2 EOR could increase to 4 million barrels a day, given adequate supplies of low-cost CO2 and **next generation CO2 EOR**. Next generation CO2 EOR is designed to store an additional 14 to 18 percent of CO2 and produce 47 percent more incremental oil. At 85 US$ per barrel and a CO2 price of 40 US$, incremental oil production could reach 67.2 bln barrels. CO2 usage could amount to 20 GtCO2, with 18 GtCO2 from anthropogenic sources.

Fig. 10: EOR potential in the USA in the next 20 years

Reservoir Setting	Oil Recovery bln Barrels		CO2 Demand / Storage MtCO2	
	Technical	Economic	Technical	Economic
Miscible CO2 EOR				
Lower 48 Onshore	104.4	60.3	32,250	17,230
Alaska	8.8	5.7	4,110	2,330
Offshore	6	0.9	1,770	260
Near Miscible CO2 EOR	1.2	0.2	800	110
Residual Oil Zone	16.3	n.a.	6,500	n.a.
Total	**136.6 bln Barrels**	**67.2 bln Barrels**	**45.43 Gt**	**19.93 Gt**

Source: NETL 2011

CO2 abatement potential is substantial, with total EOR storage amounting to 4.2 years of the US CO2 emissions of 5,49 GtCO2pa (2011) [5]. Thus, CO2-EOR has the potential of offsetting an annual 10.4 percent of US CO2 emissions. But it is the prospect of domestic oil and decreased reliance on imports that is of special appeal to US policy makers: 65 percent of the **US trade**

[4] Global CCS Institute and China sign co-operation agreement, CCJ 27(2012), p. 13; see also Yu 2013
[5] National CO2 emissions data in this report are based on http://www.eia.gov

deficit are attributed to oil imports, amounting to US$ 324 billion in 2010. CO2 EOR has the potential to decrease US import dependency by 30-40 percent and take an annual US$ 100 billion off the energy bill [ARI 2011; USCSC 2012].

In 2009, ARI estimated the **global potential of CO2 EOR** for the International Energy Agency's Greenhouse Gas R&D Programme (IEA-GHG 2009). The study identified 51 major oil basins world-wide amenable to EOR and used US analogues to estimate incremental oil production from EOR operations and the amount of CO2 stored [IEA-GHG 2009].

Global EOR was estimated at 468.5 billion barrels of incremental oil, and CO2 storage at 139.2 GtCO2. Half of these potentials are within the Middle East and North Africa. Safe for OECD countries and China, source-sink relations, i.e. the distance between CO2 emission strongholds and injection sites, are still unfavourable: Applying a 800 km source-sink distance, CO2 storage potential decreases to 65 GtCO2. Adding smaller fields adds another 51 Gt of CO2 storage potential [Fig. 11]. Estimating next generation CO2 EOR, undiscovered fields and residual oil Zones (ROZ), ARI 2010 estimates an **overall global potential of 365 GtCO2** for EOR.

Fig. 11: Global EOR & Storage potential from large and small fields

Region	Number of Basins	Large Fields		Small Fields		Annual CO2 Emissions GtCO2 (2011)	EOR abatement as % of annual Emissions
		EOR Potential (bln BBL)	CO2 Stored (Gt)	EOR Potential (bln BBL)	CO2 Stored (Gt)		
Australia	1	1.3	0.3	not specified	not specified	0.43	2.3%
Canada	2	5.7	1.7	6.7	2	0.55	10.3%
USA	14	60.2	17.2	22.6	6	5.49	10.4%
Latin America	7	44.0	14.2	11.7	4	1.34	35.3%
EU-27 (North Sea Graben)	1	14.3	4.0	6.0	2	3.84	4.2%
Eastern Europe (Carpathian-Balkanian)	1	1,9	0.6			0.67	3.6%
China	3	14.0	3.8	6.8	2	8.72	1.5%
East Asia	2	3.1	8.3			5.50	5.0%
Former USSR	6	73.0	19.9	29.1	8	2.30	28.8%
Africa	6	35.6	10.0	5.4	2	1.15	29.0%
Middle East	8	215.2	65.8	85.3	26	1.95	112.5%
Total	**51**	**468.5**	**139.2**	**173.6**	**51.0**	**32.57**	**n.a.**

Sources: Inagendo 2013, IEA-GHG 2009; ARI 2010, EIA 2013

Even given the source-sink requirement, **CO2 usage potential is substantial** and amounts to 3 GtCO2pa from anthropogenic sources. Calculating the CO2 abatement potential as a share of the 2011 annual emissions [Fig. 11, right columns], CO2 EOR stores 10.4 percent of the annual energy related CO2 emissions in North America and 4.2 percent p.a. in the EU-27. This is a substantial contribution to the CCS requirement in the IEA's 2DS climate mitigation scenario.

2.1.5 CO2 EOR: EU-27 Potentials

IEA-GHG 2009 identified two major basins in Europe: The **North Sea Graben** (NSG) and the Carpathian-Balkanian Basin, that extends over Ukraine, Moldavia, Romania, Serbia, and Turkey. Romania is part of the EU-27, with an EOR potential of 1.939 mln bbl and a storage potential of 600 MtCO2 [6]. For the North Sea Graben, incremental oil is estimated at 14.3 billion barrels, and overall CO2 storage at 4 GtCO2 [Fig. 11].

[6] For accuracy, the Romanian potentials were added to the EU-27 figure in Fig. 11

Despite these potentials, the **European Commission** remains low key on CO2 EOR: Energy Commissioner Günther Oettinger had contended that *"the only existing and short term realistic use for large amounts of CO2 is Enhanced Oil Recovery"* [GCSSI 2013a]. The ongoing consultation on the future of carbon capture and storage considers CO2 EOR potentials to be limited: *"Enhanced Oil Recovery (EOR) may help some projects, but unlike in the US and China, EOR has not been a driver for CCS deployment in Europe"* [European Commission 2013]. The consultation paper's reluctant outlook is based on a selective appropriation of an eight year old study that precedes both, the ETS era and the IEA-GHG survey [Tzimas 2005].

Tzimas selected 59 candidate fields in the North Sea Graben, amenable to CO2 EOR. Incremental oil was estimated at **7.4 billion barrels**, with a CO2 storage of about **1.8 to 3.1 GtCO2**. Under a carbon price system, CO2 storage capacity in the UK increased to 3.5 GtCO2, and in Norway to 6.2 GtCO2. The economic potentials were considered considerably lower, but – at the time of the study – oil prices were on a low.

In the mid-2000s, a number of European EOR proposals failed as well: 2006, Shell and Statoil announced to develop a large scale CO2 EOR project on Draugen and Heidrun, with 2.5 MtCO2 delivered by Tjeldbergodden gas power station. The project was cancelled due to unfavourable economics and lack of CO2 supply. CO2 EOR potentials at Gullfaks and Ekofisk fields in the Norwegian shelf have been explored, but none has been pursued. In order to develop CO2 EOR infrastructure for the Norwegian North Sea oil fields, large volumes of CO2 are needed.

CO2 from Norwegian capture plants is not sufficient to meet demand and would likely require a pipeline to deliver German, Benelux and French CO2 to support Norwegian CO2 operations [NPD 2010, ElementEnergy 2012, Holt 2009]. In the UK, BP had proposed to use CO2 EOR for DF1 Miller, but the proposal collapsed due to unfavourable economics [ElementEnergy 2012].

These proposals failed possibly due to their early mover status: The window of opportunity for CO2 EOR is tied to an oil price level of about 100 US$/bbl [SCCS 2009, Holt 2009]. 2012 DECC forecasts estimate future **oil prices at US$135/barrel**, with a low oil price scenario at U$75/bbl. Current oil prices hover around 105 US$/bbl. Hence, the window of opportunity is now open, but may close by 2020, when some NSG oil fields are about to be decommissioned.

There are two proposals including CO2 EOR in the North Sea in the EU's New Entrant Reserve programme for CCS demonstration (NER300): 2Co's Don Valley CCS Project in South Yorkshire intends to capture up to 5 MtCO2pa from an IGCC power plant. The CO2 will be transported over a 400km CO2 pipeline to two North Sea Oil fields, short of decommissioning. EOR operations are expected to yield an additional 15 percent of OOIP and extend production for another 20 years. The project failed to make the first NER-300 award in December 2012, but may be considered for the 2nd call in 2014.

Outlooks of recent studies, based on contemporary oil prices, are favourable: SCCS 2009 suggests that *"CO2-EOR may act as a stimulus for CCS especially if developers come to expect that the price of oil will remain over US$100 per barrel for the period of their investment."* Likewise, Holt 2009 contends that, for oil prices in the range of US$ 100, the CO2 price is close to the cost of CO2 capture [Fig. 12].

Fig. 12: Range of Carbon Capture Costs over the value chain

Component	t/CO2 min	t/CO2 max
Capture at Power Plant	11.00 €	55.00 €
Capture from Flue Gas	3.70 €	41.00 €
Industrial Capture	18.75 €	86.25 €
Transport	0.70 €	8.00 €
Geological Storage	0.30 €	9.00 €
Monitoring	0.10 €	0.30 €

Source: IPCC 2005, IEA 2008

A number of 2009ff studies on a national and regional scale have provided up-to date estimations on North Sea EOR potentials. They found substantial potential for CCUS and associated benefits, especially in incremental oil and for EOR as an **accelerant for CCS** [Fig. 13].

Fig. 13: Peer Review on Incremental Oil and CO2 Storage in the North Sea

Source	Candidate Fields	High Oil Price Scenario	Increment Oil [billion barrels]	EOR CO2 Storage [Gt]	EOR & Stacked Storage [Gt]
Mattiassen 2003	128 Candidate Fields	n.a.	2.0	0.65	n.a.
Tzimas 2005	59 Fields (UK,NOR,DK)	35 US$/bbl	7.4	3.10	9.7
SINTEF 2007	19 NOR Fields 30 UK Fields	variable	4.3	2.30	7.3
Holt 2009	Select Norwegian and UK Oil Fields	90-160 US$	4.1 to 4.4	2.28	7.3
IEA-GHG 2009	North Sea Graben	70 US$/bbl	14.3	4.00	8.0
SCCS 2009	14 Fields (Scottish North Sea)	100 US$/bbl	3.0	0.99	n.a.
Godec 2011	North Sea Graben	70 US$/bbl	16.2	4.70	n.a.
ElementEnergy 2012	19 Fields (UK Continental Shelf)	90 US$	6.8	2.10	n.a.
DIW 2013	54 UK Fields	92 - 135 US$/bbl	1.7	0.57	n.a.
	7 NOR Fields		1.0	0.31	
	13 DK Fields		1.1	0.35	

Inagendo 2013

In general, regional estimates on the North Sea Graben EOR potential yield more cautious results than IEA-GHG 2009, for two reasons:

- First, the IEA-GHG data is based on US analogues, with favourable specifics that do not mirror NSG offshore environments. **Offshore operations** are high-cost operating areas. NETL 2010b analysed offshore potentials in the Gulf of Mexico. Albeit technical potentials amounted to 5.8 billion barrels and 1.7 GtCO2 storage, only 730 million barrels and 200 MtCO2 were economic at an oil price of US$70/bbl and a CO2 price of US$45/t. NETL 2010b, thus, contends that offshore operations require higher oil prices of 100 US$/bbl, lower CO2 costs (35 US$/tCO2) and reduced royalties or credits for the storage of CO2.

  This is commensurate with recent North Sea studies which put the threshold for an economic application of CO2 EOR in the North Sea Graben at an oil price of US$ 100 [Holt 2009, SCCS 2009, ElementEnergy 2012]. This is due to the fact that storage costs in offshore environments tend to be two to three times as high as onshore storage [Fig 14].

Fig. 14: Storage Costs On/Offshore

Region	On-Shore / Off-Shore	t/CO_2 min	t/CO_2 max
USA	onshore	0.30 €	3.40 €
Europe	onshore	1.40 €	4.60 €
Europe	offshore	3.50 €	9.00 €

Source: IAE 2008; IPCC 2005

- Second, many NSG fields have already been extensively water flooded. On average, primary and secondary oil recovery by water flood from NSG oil fields accounts for 45% to 55% of the OOIP [SCCS 2009, DIW 2013]. Thus, incremental oil production from CO2 EOR might be lower than assumed by IEA-GHG 2009 [Fig. 15].

Fig. 15: Incremental Recovery Factor of CO2 EOR in the North Sea Graben

Source	Incremental Recovery Factor from CO2 EOR In Percent of OOIP
Godec et al (2011)	11 percent (average Europe)
IEA-GHG (2009)	23 percent (Next Generation CO2 EOR)
Scottish Center for Carbon Storage (2009)	5 to 15 percent (Scotland)
ElementEnergy et al (2012)	7 to 11 percent (UK,NOR)
Holt et al (2009)	8.8 percent
Tzimas et al. (2005)	4 to 12 percent

Source: Inagendo Update of DIW 2013

Still, NSG estimates provide for substantial potentials in incremental oil and CO2 storage: SCCS 2009 identified 14 candidate fields amenable to EOR for the **Scottish part** of the NSG. EOR potential, including Statfjord field (UK/Norway), was estimated at 3,018 mln barrels of incremental oil and CO2 storage at 994 MtCO2. SCCS contends that – at CO prices from 28 to 56 US$ - CO2 EOR needs an oil price level above 100 US$/bbl. Eunomia 2011 identified smaller EOR opportunities in the **East Irish Sea**. Three producing oil fields in the Liverpool Bay are amenable to CO2 EOR, with a total CO2 storage capacity of about 150 MtCO2.

ElementEnergy 2012 identified 19 oil fields in the **UK Continental Shelf (UKCS)** as 'anchor' projects for CO2 EOR. Incremental oil recovery was estimated at 6.8 billion barrels, with a CO2 storage of 2.1 GtCO2. A cluster of CO2 EOR projects could contribute 15 percent of UKCS oil production in 2030. Holt 2009 estimated EOR potentials of 19 UK and 30 Norwegian fields, with a 70 percent overlap with the fields considered by ElementEnergy 2012. Holt estimations deliver conservative results, assuming average recovery efficiency at 8.8 percent of OOIP, while field-by-field assessment of ElementEnergy result in an average 10 percent of OOIP.

Holt 2009 gives EOR potential at 4.1 to 4.4 billion barrels and CO2 storage at 2.28 GtCO2, plus an additional 5.1 GtCO2 in stacked storage: Holt, thus, estimates an annual injection of 178 MtCO2pa, to support EOR production over a lifetime of 15 to 20 years. In the remaining years, CO2 injection is targeted to incremental storage. Calculating CO2 costs at 27 US$/tCO2, the oil price level for economic operation was found to be at 70 US$/bbl. If the CO2 price were at a level to support power plant capture, i.e. above 57 US$ per tCO2, an oil price level of 100 US$/bbl were necessary to support EOR operations. In that case, Emden/Germany and Aberdeen/UK could be used as export terminals, collecting CO2 streams from West Europe and the

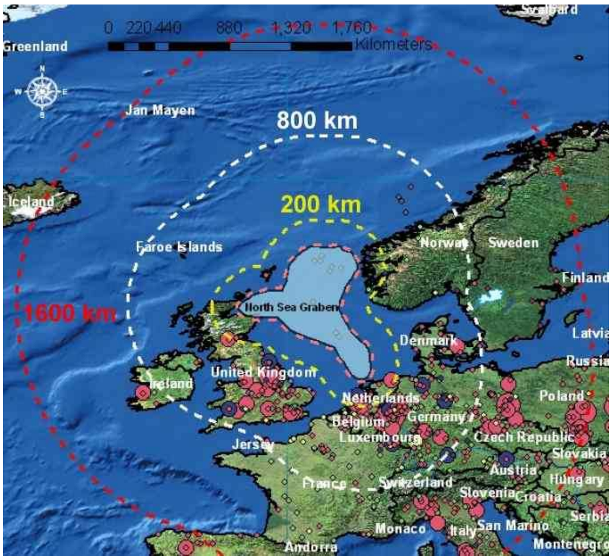
UK to injection wells in the North Sea fields under consideration. Average transport costs via pipeline amount to 6 US$/t$CO_2$, with sequestration costs of 4.0 US$/t$CO_2$.

DIW 2013 analysed CO_2 EOR potentials in 74 oil fields in the **UK, Norwegian and Danish parts of the North Sea**. For UK and Norway, DIW 2013 assumed a rather conservative recovery factor of 4 percent of the OOIP. Recovery factor for DK fields was set at 8 percent, as Danish fields have not been extensively water flooded. EOR potentials were calculated at 3.8 billion barrels of incremental oil and CO_2 storage at 1.23 GtCO_2. These potentials seem conservative, since EOR recovery factors from the Heriot Watt database for the UK and Norwegian fields are aligned around 10 percent of the OOIP [ElementEnergy 2012].

DIW 2013 also estimated the costs of CO_2 delivered to well-head. Costs range between **67€ and 83€ per tCO_2**. DIW concedes that CO_2 costs are possibly overestimated. US analogues assume a CO_2 price in the range of US$ 29 to 58, given an oil price level of about US$ 100 [USCSC 2012]. DIW indicates that investments in CO_2 EOR operations in the NSG are beneficial in all scenarios, especially so under a high oil price scenario: In such a scenario, CO_2 EOR would serve to initiate investments in a pipeline infrastructure in the North Sea for the first 25 years. Upon cessation of EOR operations, the infrastructure might then be used for CCS.

Full exploitation of CO_2 EOR potentials requires vast amounts of anthropogenic CO_2 in the vicinity of injection sites. Applying a 200 and 800 km diameter around the North Sea Graben, sufficient volumes of anthropogenic CO_2 are available in large **CO_2 clusters** [Fig. 16].

Fig. 16: Distance of Large Point CO_2 Sources to CO_2 EOR sinks



CO_2 sources within ...	High Concentration CO_2	Low Concentration CO_2	Total
200 km Radius	526 MtCO_2	1.196 MtCO_2	1.722 MtCO_2
800 km Radius	1.853 MtCO_2	22.090 MtCO_2	23.943 MtCO_2
CO_2 Demand for EOR			3.691 MtCO_2

Source: IEA-GHG 2009

Since domestic CO_2 is not sufficient to support EOR operations in the Norwegian and Danish parts of the North Sea, these fields need CO_2 supplies from Germany and France via Belgium and the Netherlands. CO_2 supplies to UK fields would come from UK industrial CO_2 clusters, delivered via St. Fergus, Scotland [DIW 2013].

SCCS 2013 cites the lack of available high-purity CO2 as an essential hurdle and suggests the prioritised use of CO2 released from Ammonia. CO2 from Ammonia has already been separated during production, making **5.42 Mt of high purity CO2** available in less than 200km distance off available storage fields off the coast of the Netherlands and North England.

The principal beneficiaries of CO2 EOR clusters in the North Sea would be the governments of the **UK, Norway and Denmark**, as a result of the taxes applied to the offshore industry. Tax receipts could in principle be offset against public subsidies for CCS. CO2 EOR could, thus, be an enabler for CCS [ElementEnergy 2012]. UK, DK, and NOR governments should also consider to introduce a reduced oil tax rate for the use of anthropogenic CO2, as exemplified by Texas. Moreover, CO2 EOR could take **300-544 billion €** off the EU-27 energy bill and decrease reliance on imported oil from politically unstable regions. Countries with no onshore-CCS storage, like France, or onshore storage moratoriums, like the Netherlands and Germany, might profit from the sale of CO2 to NSG EOR oil fields in Norway and Denmark.

2.1.6 European CO2 Abatement Potential of CO2 EOR

There is quite some debate – if not to say highly polarised **controversy** – around CO2 EOR as an accredited mitigation strategy to combat climate change. Concerns are whether CO2 EOR may be considered a genuine GHG abatement option at all, and the sequestered CO2 will be permanently removed from the atmosphere, regarding CO2 leakage and long-term retention.

Opponents claim that CO2 EOR is not a GHG abatement option, but, on the contrary, results in more, not less, CO2 emissions. Their case is that CO2 EOR produces significant amounts of "additional oil" that will eventually be combusted. Proponents hold that incremental oil from EOR **displaces** oil that would otherwise be produced by conventional means. Traditional oil exploration produces twice the amount of CO2 than attributable to EOR. Edge 2011 conducted a life cycle assessment on the Weyburn-Midale EOR project and assessed CO2 emissions over the value chain at 0.51 tCOe per 1 tCO2 stored. Compared to traditional oil, 49 percent of overall emissions were saved. Individual oil fields will have greater capacity to store CO2 than results from an EOR operation. Hence, next generation EOR and post-operation storage might remove significant larger amounts of CO2 from the atmosphere, than generated by the incremental oil, ranging between 74 and 129 percent of the CO2 emitted during EOR operations [Fig. 17].

Fig. 17: Life Cycle Analysis of Next Generation CO2 EOR (US Gulf Coast Case Study)

	Next Generation	Second Generation CO2 EOR & Storage		
	CO2 EOR	CO2 EOR	Storage	Total
CO2 Storage	32 MtCO2	76 MtCO2	33 MtCO2	109 MtCO2
Storage Capacity Utilisation	22 percent	53 percent	23 percent	76 percent
Oil Recovery	92 mln bbl	180 mln bbl	-	180 mln bbl
% Carbon Neutral	74%	90%	-	129%

Source: ARI 2010

It is safe to say that CO2 EOR increases the amount of technically recoverable reserves: As reserves and oil prices are a system of communicating vessels, CO2 EOR inevitably increases the amount of oil available to a carbon hungry world, taking some pressure off the need to develop alternative solutions. Thus, CO2 EOR is buying time away from following **more risky oil ex-**

ploration venues, such as deep-water drilling and sub-seabed oil production. It also reduces the need to explore new sources and associated land use.

NGOs fear that CO2 EOR will extend the fossil fuel age. This is only so in a carbon unrestrained world. With **binding climate targets** in place - such as in the European Union - it is not oil price level but carbon intensity that matters. Carbon intensity of North Sea EOR oil, which is augmented by CO2 during EOR operations, is estimated at an average 54 kgCO2e/bbl. It will most likely replace Saudi oil imports, with an average 40 kgCO2e/bbl, that come with no CO2 sequestration at all. Therefore, CO2 emissions reduction of NSG EOR oil, in comparison to a non-EOR scenario, amounts to 40 percent [SCCS 2013]. With incentives that account for additional CO2 sequestered, abatement could double to 70-80 percent, with post-operation storage exceeding 100 percent.

Thus, under binding European ETS targets, CO2 EOR offers a **substantial carbon abatement potential**. North Sea EOR oil would likely displace imported oil in the transport sector, not yet covered by the ETS. Here, NSG EOR oil could substitute Saudi oil, reducing CO2 emissions by 40 percent and taking an annual **17 to 28 billion €** off the EU energy bill.

Opponents still hold that the EOR potential of 7.3 to 8 GtCO2 for sequestration is insignificant, when compared to annual EU CO2 emissions of about 3.8 GtCO2 (2011). This is a somewhat awkward comparison: There is no single abatement technology held responsible for tackling 100 percent of Europe's CO2 emissions. Carbon abatement of CO2 EOR should be assessed relative to the required CO2 reduction, mandated by the 30 percent reduction target of the EU: If the 2030 target requires to reduce EU emissions to 2.8 GtCO2, then CO2 EOR has the potential to offset **178 MtCO2pa** – or **17.8 percent** – towards that goal. This is anything but insignificant, and on par with contributions from energy efficiency and renewable energies.

Retention - that is: securing the permanent storage of the injected CO2 - is another issue: Typically, during EOR operations, 40 percent of the initially injected CO2 stays within the reservoir. The CO2 returning with the produced oil is separated and reinjected. Ultimately, CO2 EOR is a loop cycle, with **94.0 to 100.0 percent** of the injected CO2 finally residing in the reservoir, after closure of EOR operations. As oil companies have traditionally focused on incremental recovery, not on CO2 storage, they have implied that the injected CO2 resides permanently in the reservoir, since the original oil had been contained there for millions of years.

A number of projects, such as CO2SINK in Ketzin/Germany and the Weyburn IEA-GHG project, have confirmed that resilience. To identify possible risks through leakage of the CO storage reservoir, Zimmer 2011 monitored the natural CO2 emanation at the surface of Ketzin test site. Comparing the specifics of natural CO2 emanating from the soil - which can be substantial: 38 tCO2/ha at Ketzin site -, and the injected CO2 allows for identifying leakage, if any, upfront.

Evidence from large scale EOR operations comes from the Weyburn-Midale EOR Project. Weyburn has been dubbed the "Poster Child" for large scale CO2 EOR operations, since it combines both, EOR operations and carbon mitigation: The project intends to inject 23 MtCO2 for EOR purposes, and after depletion and closure of EOR operations, another 32 MtCO2 solely for purposes of storage (CCS), thus **permanently removing 55 MtCO2** from the atmosphere. On the US side, the project captures about 2.8 MtCO2pa at the Great Plains Synfuels Plant in Beulah/North Dakota, a coal gasification plant. The CO2 is transported by a 344 km pipeline and injected into two depleting oil fields in Weyburn/Canada. The project has been extensively studied and includes monitoring of the underground behaviour of CO2.

In 2011, there were allegations about **CO2 leakage** in the vicinity of Weyburn. Using isotope dating, the CO2 emanating from the ground was found to be of younger and biogenic origin, since its Carbon-14 content is absent from the isotopes of the Dakota plant CO2, used for injection. Extensive samples showed no trace of CO2 of the injected kind (PTRC 2011).

Recognition of CO2 EOR as an abatement technology thus requires a) that anthropogenic CO2 emissions are utilised, which would otherwise be vented into the atmosphere, b) the displacement of traditional oil in terms of volume ("additionality") and c) the constant monitoring and verification of CO2 EOR operations during and after operations.

2.2. Enhanced Gas Recovery (EGR)

Enhanced gas recovery is still in its infancy and mentioned for the sake of completeness. EGR techniques are similar to CO2 EOR. With primary production already releasing 70 to 95 percent of the original gas in place, CO2 injection rather serves to maintain reservoir pressure and increase the rate of gas production. Gaz de France has tested CO2 EGR on a pilot scale at its K12B project in the Netherlands. Germany's CLEAN project was stopped before actual operations. The costs associated with separating the CO2 from the produced gas will *"most likely not justify enhanced gas recovery operations"* [CSLF 2011]. CO2 separation from gas is either used for direct CO2 sequestration, as in the large scale In Salah, Snøhvit and Sleipner projects, or redirected to CO2 EOR, as in the US [GCSSI 2013cd].

2.3. UREA Yield Boosting

UREA accounts for 50 percent of the global nitrogen fertiliser production. It is produced by a combination of ammonia and carbon dioxide at high pressure and temperature. CO2 capture plants for urea yield boosting have been installed since the late 1990's. Production of UREA amounted to 151.9 Mtpa in 2009, and is growing strongly in China (65 Mtpa) and India (25 Mtpa). Global CO2 demand for UREA amounts to 100 MtCO2pa [GCSSI 2011]. For every tonne of urea produced, 0.73 to 0.75 tCO2 are utilised, but production results in 2.27 tCO2 emitted per 1 tCO2 supplied [Edge 2011].

The production results in negative carbon abatement, with fertilisers being the major source of agricultural CO2e-Emissions. UREA yield boosting, thus, may be considered a modest CO2 reuse application, but **not a viable carbon abatement option**.

3. Emerging Uses

3.1. Enhanced Coal Bed Methane (ECBM)

CO2 ECBM technology is similar to EOR. Carbon dioxide is injected into the coal seam, eventually releasing incremental methane (CH4). CO2 ECBM has the potential to increase methane production to 90 percent of the gas in place, compared to conventional recovery of 50 percent by reservoir pressure [DOE 2012]**.** Unmineable coal beds also provide for a large **CO2 sequestration potential**, as the CO2 is absorbed and permanently retained by the coal.

CO_2 ECBM is associated with some hindrances that have hitherto prevented its wide application: Coal may swell with the adsorption of CO_2, which will reduce the permeability, thus restricting application to depths between 800 and 1000m [Bachu 2008]. This explains the limited success of pilot operations for CO_2 storage in coal beds run in Canada, Poland, China and Japan [IPCC 2005]. The US Department of Energy foresees large scale application of ECBM for the time past 2025 [DOE 2010]. **Incremental recovery efficiency** of CO_2 ECBM depends on reservoir characteristics, with 1.5 to 10 cubic meter of CO_2 injected for every cubic meter of CH_4 released, and a base case of 2 units CO_2 per unit CH_4 [IPCC 2005].

Albeit yet small in application, the theoretical potential of ECBM is significant: Incremental methane is estimated at 18 trillion cubic metres (Tm3), with a global sequestration potential of **345 GtCO2**. DOE 2012 estimates the US potential at 60 to 117 GtCO2. CO_2 ECBM is considered to be economic at natural gas prices of US$ 62 to US$ 71 per cubic meter, with capture, transport, and sequestration costs under US$50/tCO2 [NCC 2012]. Given the boom of US shale gas, which also impedes the economics of US EOR, it is unlikely that ECBM will reach an economic scale before the medium to long term, if not carbon price incentives for the associated CO_2 storage offset some of the costs that come with its application.

ECBM is of special appeal to countries with a) large coal resources, b) increasing energy demand and c) ensuing CO_2 emissions, such as China and India. Estimations of China potentials hold that 143 GtCO2 may be stored, sequestering 16 years of Chinas 2011 CO_2 emissions (8.17 GtCO2). The production of methane from ECBM is estimated at 3.4 to 3.8 Tm3, with the additional benefit of substituting coal as a major energy source. CO_2 emissions from methane combustion are at average 60 to 70 percent lower than from coal fired power plants. Thus, a fuel switch from coal to methane would significantly reduce China's **coal-based CO2 emissions,** thereby providing some climate mitigation potential [CSLF 2011; GCCSI 2011].

3.2. Enhanced Geothermal Systems (CO2 EGS)

CO_2 EGS is a novel technology that enables energy production from formations that would otherwise not be suitable as a geothermal energy source. CO_2 mobility in micro-porous environments is five times superior to water and 10 times superior to brine, thus exploiting heat from low-permeable zones, previously not accessible [IEA 2013c]. The CO_2 is injected into geologic formations at depths of 0.8 to 5.0 km, where it circulates as a working fluid to recover the geothermal heat. The heat is either transferred to a power cycle fluid or generates power through a supercritical CO_2 turbine. The CO_2 is then separated from any remaining water or hydrocarbons, condensed in a heat exchanger and reinjected, closing the loop, so that no CO_2 is released into the atmosphere.

CO_2 EGS is not only superior to traditional water/brine injections, since it reduces the need for clean water, but also avoids "parasitic" pumping of heat, which comes with a large energy penalty. CO_2 EGS at 2.5 km depth with moderate permeability operates at 11.8 percent energy conversion efficiency; traditional water/brine operations attain only 3.4 percent, since they are plagued with energy losses due to pumping and friction [7].

Geothermal energy provides for a reliable source of **baseload electricity**, albeit it is the most expensive technology in the renewable portfolio [Fig. 18]. CO_2 EGS stores substantial amounts

[7] CO_2 storage with geothermal energy production, CCJ 27 (2012), pp. 16ff

of CO_2 in the underground, with a carbon abatement potential of about 56 percent. Estimations suggest that a 10 MW power system might store around 100 ktCO_2 [DOE 2012]. Commensurate, the Australian Geodynamics EGS project expects an annual use of 4.4 MtCO_2pa for its 500 MW EGS, expected by 2018.

EGS is of special appeal to countries with **high geothermal activity**, such as Iceland, New Zealand, Australia, and the East African Graben: Australian geothermal potential is estimated at 22,000 Exajoule. EGS may provide up to 5 GW or 10 percent of Australian electricity by 2030. There is currently no information about EGS potential in Europe.

Fig. 18: Cost assumptions for renewable electricity generation

	Investment US$/kW		O&M Cost US$/kW p.a.	
	2010	2050	2010	2050
Baseload Technology				
Biomass Steam Turbine	2,500	1,950	111	90
Geothermal	2,400 - 5,500	2,150 - 3,600	220	136
Large Hydro	2,000	2,000	40	40
Intermittent Renewables				
Solar PV	3,500 - 5,600	1,000 - 1,600	50	13
Ocean	3,000 - 5,000	2,000 - 2,450	120	66
Wind onshore	1,450 - 2,200	1,200 - 1,600	51	39
Wind Offshore	3,000 - 3,700	2,100 - 2,600	96	68

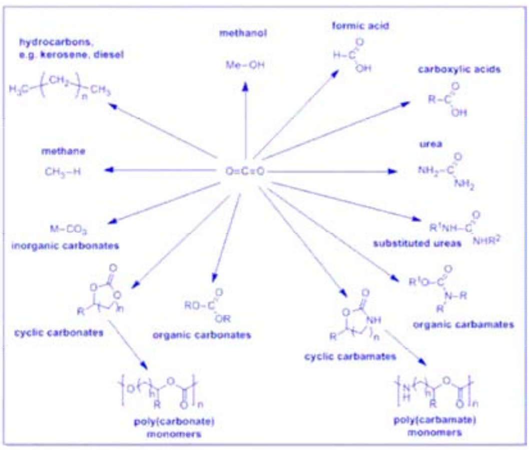
Source: IEA 2010

The most significant drawback of the technology is **high cost, low maturity**: The technology is not yet proven, with a first CO_2 EGS project planned for 2013 [GCCSI 2011]. IEA 2012b expects significant EGS deployment in the phase past 2050: EGS is then thought to double geothermal electricity production from 1 500 TWh in 2050 to 3 000 TWh in 2075. For the time being, EGS is **not a near-term CCUS option**.

3.3. CO2 as a Chemical Feedstock

As many chemicals use petrochemical feedstock for production, there are some venues to substitute the carbon backbone with the carbon component of CO_2 [Fig. 19].

Fig. 19: Venues for Chemicals produced from Carbon Dioxide



Source: CFLCF 2011

Technologies are currently in their infancy, with major drawbacks: Due to its low energy state, conversion of CO2 either requires **large amounts of clean energy** or **better catalysts** than available to date [Bennet, Essen 2013].

Interesting venues, in terms of market size, are polycarbonates, polypropylene carbonates (PPC) and polymers. Traditional monomers can be combined with CO2 to produce polycarbonates, such as polyethylene carbonate and polypropylene carbonate. Polymers are traditionally produced by using petroleum derived products, such as ethylene or propylene, to form polyethylene (PE) or polypropylene (PP) [DOE 2012]. CO2 may be used to synthesise polymers by transforming carbon dioxide, using zinc based catalysts, which react with the CO2 at low temperature and pressure, This would provide a low energy pathway for plastics, which contain up to 50 percent of carbon dioxide.

Bayer of Germany announced to produce "some thousand tonnes" of polyurethane from CO2 and renewable energies at its Dormagen demonstration facility from 2015, with batch-scale production envisioned for 2020. Bayer uses a zinc based catalyst and CO2 provided by an RWE power plant to produce polyol, one of two intermediates of polyurethane. For the second intermediate, isocyanate, Bayer produces hydrogen from CO2, using renewable energies. The hydrogen will in turn produce carbon monoxide, and ultimately isocyanates [Guertler, Brussels 2012]. RWTH Aachen is conducting a life cycle assessment of the process, resulting in a net abatement of about **20 percent**, compared to traditional production [8]. As the global market for polyurethanes is estimated at 13 Mt, replacing all fuel-based by CO2 based polyurethanes would amount to 2.6 MtCO2pa, with future potentials estimated at 3.3 MtCO2pa.

The global markets for polyethylene and polypropylene are 80Mt and 45Mt respectively, representing the two largest polymer markets. Overall CO2 usage potential of chemical applications remains difficult to assess, due to the vast product portfolio. VDI 2009 estimated the **annual potential at 84 MtCO2pa**, with remaining insecurity about abatement. Bennet [Essen 2013] gives global future CO2 demand for polymers at 30 MtCO2pa and for plastics "well below" 50 MtCO2pa.

These are neither substantial amounts, if compared to global emissions, nor do chemicals provide for **significant abatement**. Abatement would require the use of excess renewable energies **and** the use of CO2 of biogenic origin. Considering permanence, the CO2 content would be re-released into the atmosphere at the end of the product's life cycle. While polycarbonates can essentially retain CO2 forever, the persistence of plastics is rather seen as an environmental hazard, not as a valuable CO2 sink.

3.4. Concrete Curing and Bauxite Residue

Global cement production amounted to 2.9 Gt in 2009, with corresponding concrete production at 10 Gt, and substantial growth envisioned for the next decades (3.69-4.40 Gt in 2050). The production of 1 tonne of cement releases 0.73 tCO2, making cement a **major source of anthropogenic CO2 emissions**, providing for 2.14 GtCO2 in 2009, amounting to 7 percent the world total. The industry is, thus, attempting to reduce the carbon intensity of the product. Concrete curing is a – yet immature – technology that uses CO2 from onsite flue gases and local combustion sources to cure precast concrete products, replacing the traditional energy intensive steam

[8] Essen Conference 2013; Welt am Sonntag, 25 Aug 2013

curing approach. When concrete is cured using CO2, the CO2 is converted to calcium carbonate. A US R&D programme seeks to improve the CO2 curing of precast concrete to accelerate strength gain, reduce energy consumption, and increase durability [DOE 2012].

The technology may only be applied to precast concrete, roughly 10 percent of total concrete: If all concrete were carbonation treated, curing might take 0.12 tCO2 per unit or a total of **60 MtCO2pa** off the global emissions [GCCSI 2011]. This would but serve to offset the significant growth of the cement market until 2050; so CCS remains the only viable venue to reduce CO2 emissions from cement production.

Other CO2 abatement technologies for cement and concrete include CO2-consuming inorganic binders as a substitute for Portland cement and the Calera process that directly mineralises CO2 in flue gas to carbonates, similar to mineral carbonation [see section 3.5] [9]. All technologies are in their infancy and yet unproven on a batch scale. China Huaneng & Peabody have announced to use Calera at Xiliguole 1.2GWe supercritical coal plant to provide local building construction materials [Priestnall, Essen 2013].

Treating **bauxite residue** with CO2 provides for another permanent CO2 storage solution. The technology treats high alkaline residues from alumina production, known as “red mud”, with CO2, providing for direct carbonation. Bauxite residue is essentially a hazardous by-product, that, when treated with CO2, transforms into a harmless residue and may be used for construction or soil improvement. Alcoa’s proprietary technology uses 35 kg of CO2 per tonne of residue. Application in the global aluminium industry, producing an annual 70Mt of red mud, would sequester 2.45 MtCO2pa. If focus were on storing CO2 instead of merely neutralising alkalinity, potential CO2 storage could amount to up to 0.7tCO2 per tonne of red mud, or 49 MtCO2pa.

3.5 Mineral carbonation (MC)

Mineral carbonation is no CO2 reuse process but an alternative concept for long-term CO2 storage. The process mimics nature, where alkaline and alkaline-earth oxides react chemically with CO2 to produce minerals such as magnesium oxides (MgCO3) and calcium oxides (CaCO3). **Natural carbonation** is a very slow process. A key challenge for large scale deployment of CO2 mineralisation is acceleration of the carbonation, which is achieved by micro-grinding and chemical processes. Mineralisation provides for a permanent, leak-free fixation, with no need for long term monitoring. Since the minerals concerned are essentially ubiquitous [Fig. 20], MC provides for theoretically **unlimited storage capacity**. The process might also use CO2 directly from flue gas, with no previous carbon capture.

Fig. 20: Minerals for Mineral Carbonation

Mineral	Chemical Transformation Process	Heat of Reaction
Serpentine	Mg3Si2O5(OH)4 + 3CO2 → 3MgCO3 + 2SiO2 + 2H2O	dH = -64kJ/molCO2
Olivine	Mg2SiO4 + 2CO2 → 2MgCO3 + SiO2	dH = -89kJ/molCO2
Wollastonite	CaSiO3 + CO2 → CaCO3 + SiO2	dH = -90kJ/molCO2
Brucite	Mg(OH)2 + 2CO2 → Mg(HCO3)2 (in ocean)	dH = -134kJ/molCO2

Source: Priestnall, Essen 2013

[9] Calera - using CO2 to make useful materials, CCJ 16(2010), pp. 23ff.

Albeit mineral carbonation is an exothermic process, releasing energy, there is a **substantial energy penalty** for crushing and milling the mineral to around 100 microns and heating for speeding up the chemical process. Transportation of vast amounts of rock may also use substantial energy, if carbonation plants are not sited at mining sites.

Mineral carbonation requires 1.6 to 3.7 tonnes of rock to fix 1 tonne of CO2 and produces 2.6–4.7 t of carbonate rock per tonne of CO2. This comes with a significant land requirement, for both, the initial mining and landfills for the final deposal, plus associated transportation costs. The environmental impact is similar to large scale surface mining operations (coal, copper).

The technology is not yet mature enough to allow for a proper assessment of **costs and performance**. IPCC 2005 indicates that CO2 abatement costs could range between 50 and 100 US$ per tonne of CO2 avoided. The access to rocks for mineral carbonation, the high energy penalty and environmental impact, and the **high cost** make large scale implementation unlikely before 2025 [Bachu 2008].

4. Liquid Fuels

4.1. Algae Cultivation

Biological mitigation of CO2 is based on photosynthesis: Algae use CO2 and water, with energy provided by sunlight. The resulting biomass can be used for electricity generation or as raw material for the production of transportation fuels and bio-based chemicals. Microalgae have a **high biomass productivity** compared to terrestrial crops, and can be cultivated on non-arable land and in brackish water. Flue gases serve as the CO2 source and as a nutrient supply. On average, algae will absorb 1.8 tCO2 per tonne of biomass, with a carbon content of 0.5 tonnes, releasing oxygen in the process.

Microalgae are cultivated in open-pond systems or in (semi) closed photobioreactors, that are supplied with water, nutrients and CO2. The process requires moderate amounts of energy for mixing, as the biomass needs to be constantly “paddled”, to expose all algae cells to light, and substantial energy (10 times the energy for conventional crops) for the drying of the biomass. High Rate Algal Ponds (HRAP) are the most common method for commercial algae production, with an average cost of 10 US$/m2. Large scale open systems come with some risks, especially contamination issues and the associated risk of CO2 outgassing.

Semi-closed or closed photobioreactors offer a controlled environment: They may also cultivate algae species with higher productivity, unviable in open systems. Bioreactors can be used on non-arable land or in deserts, provided sufficient CO2 supplies. Major drawbacks are associated costs, which is 10 times the cost of open pond systems (> US$ 100/m2), and limited scalability.

Current global fuel production from microalgae is at 10,000 tonnes p.a., indicating the very infancy of the technology. Production efficiency is limited to 80 tonnes of dry biomass per hectare and year, with an energy conversion efficiency of around 1 percent. Cost estimations for microalgae production depend on scale: At 1 ha scale the cost per kg biomass is given at 10 €/kg, at 100 ha scale at 4€/kg. It is expected that learning curves will possible result in 0.60 €/kg [Barbosa, Essen 2013]. Prices for algae based fuels are not considered to be competitive with crude oil equivalents until costs of algae cultivation and processing significantly decrease [GCCSI 2011].

Albeit land requirement for algae cultivation is considerably lower than for traditional biofuel crops [Fig 21], it is still significant, possibly prohibitive to large scale deployment in densely populated countries.

Fig. 21: Land Requirement for covering 50 Percent of US Fuel

Crop	Oil yield (L/ha)	Land Area needed (Mha)	% of US cropping area
Corn	172	1,540	846.0%
Soybean	446	594	326.0%
Oil Palm	5,950	45	24.0%
Microalgae	136,900	2	1.1%

Source: CFLCF 2011

The fixation of the CO2 emitted by a 600 MWe coal fired power plant with 4.38 Gt of CO2 emissions p.a. would require an algae cultivation space of about 200-300 km2 [CFLCF 2011]. Commercial scale systems are typically sized about 10 to 100 hectare, absorbing anywhere between 500 tCO2pa to 55,000 tCO2pa. As algae production comes with substantial land requirements, the technology is most suited to regions with high solar resource and large areas of marginal land, surrounding point CO2 sources. Commensurate, the Microalgae Bio-Energy and Carbon Sequestration Project in Dalate (Inner Mongolia) is the largest pilot to date: The project uses microalgae to absorb an annual 320 ktCO2 from coal-based flue gas to produce bio diesel as well as feed-stock.

Algae based fuels provide for no permanent CO2 abatement, as the contained CO2 is returned to the atmosphere upon combustion. But they still offer significant abatement potential as they **substitute fossil fuels**, with a CO2 reduction of 58 percent over the life cycle [Edge 2011]. Albeit land requirement is huge, it is still small compared to alternative crops, used for bio fuels [Fig. 21]. Moreover, algae may be grown on non-arable land and in saline-water conditions, avoiding much of the food-fuel controversy surrounding traditional energy crops, such as corn, or deforestation issues, associated with the conversion of (coastal) forests to oil palm plantations. Thus, algae fuels may provide a viable venue to **substitute conventional bio fuels**, considering the growing debate over environmental and societal impacts of energy crops.

4.2. Renewable Methanol

Renewable Methanol provides for an intriguing venue for CO2 recycling that is essentially carbon neutral. (Excess) electricity from renewable energy sources (RES) is used for the electrolysis of water into hydrogen (H2), with subsequent catalytic conversion of H2 and CO2, resulting in methanol and water:

$$CO2 + 3\ H2 \rightarrow CH3OH + H2O$$

On average, 1 MWh of methane utilise 200 kg of CO2. The concept has been broadly discussed in Germany, as a possible option to store and converse excess electricity from volatile wind [IWES 2011, DVGW 2013]. With electricity storage options from pumped storage or battery buffering limited, renewable methanol may be a venue to buffer excess RES electricity. The energy efficiency of the process is still poor: **Energy conversion efficiency** of power to gas is 49 to 64 percent, when used for electricity generation 30 to 38 percent. But if the alternative were load-shedding, utilising excess RES electricity would preserve a third to a half of the RES value.

RES methanol also provides for a "bridge" from the electricity sector to the transport and heating sector. RES methanol may be blended with natural gas, up to 5.0 – 6.5 percent of overall gas, using the gas pipeline grid for storage. It might also be refined into CNG fuels for the CNG automotive market. Low efficiency and limited CNG infrastructure are a barrier to using RES methanol in the transport sector, and electricity vehicles might offer a more energy efficient use for RES electricity: *"It is possible that in the longer-term electric vehicles will prove to be significantly cheaper."* [GCCSI 2013]

To be a commercial carbon capture and recycling option, renewable methanol requires the use of zero cost excess renewable energy and essentially zero cost CO2: The only environment, currently amenable for commercial application on a batch scale, is in geothermal systems with large amounts of excess energy and CO2 streams, such as Iceland or New Zealand: CRI produces 5 million litres of RES fuel at Iceland's 76.5MW Svartsengi Geothermal Power Station: The plant provides for the required power and volcanic CO2, resulting in methanol that is blended with unleaded petrol and sold at gasoline stations around Reykjavik.

Renewable methanol does not provide for permanent CO2 abatement: Upon combustion, the CO2 is returned to the atmosphere. The usage of CO2 streams **from biomass CCS** would result in negative carbon emissions, as the CO2 were removed from the atmosphere by the biomass in first place, with CCS storing the CO2 safely underground. DVGW 2013 contends that biogas plant emissions in Germany were sufficient to provide for the biogenic CO2. Still, the technology is competitive only in the absence of CCS, as CCS provides for lower CO2 abatement costs. DVGW assumes renewable methanol to be cost efficient, if production costs are on par with natural gas and CO2 certificate costs. 2020 production costs are estimated at **0.12 €/kWh**, decreasing to about **0.07/kWh** in 2050. Given the current US shale gas boom, RES methanol costs will possibly not be on par with natural gas well into the 2020s.

5. Abatement Potential of Industrial Applications

Industrial CO2 use is estimated at 115 MtCO2pa, with urea production accounting for 60% of that total. This represents 0.4% of the global anthropogenic CO2 emissions, amounting to 31.2 Gt [IEA 2012b]. Most of the chemical applications are in nearly saturated markets, with only a modest market growth expected in the next decades.

The abatement potential of the above total is lower: Most applications do not permanently remove the CO2 from the atmosphere, but only for the lifetime of the product, which can range from days (methanol), months (Urea), to centuries for carbonates and polyurethanes. At the end of the product's lifecycle, - which in construction could well extend 100 years -, the contained CO2 would be re-released into the atmosphere [Fig. 22].

Moreover, the use of CO2 as a carbon feedstock does not always replace fossil fuels. Due to its low energy state, CO2 fails to provide the energy necessary for most chemical processes. Fossil replacement energy will leave the CO2 emissions almost unchanged. Evaluated over the whole life cycle of production, some applications cause more CO2 emissions than is saved by the initial CO2 used, thus providing no carbon abatement option (such as UREA). Edge 2011 analysed the life cycle for specific CO2 Reuse technologies to estimate their carbon mitigation potential. Figure 23 amends Edge 2011 findings with an estimation on both, the scalability of CO2 reuse and resulting abatement costs. Scalability refers to an application's potential to uptake great amounts of anthropogenic CO2. Abatement costs are an estimation of the position of a technology in a CO2 per tonne mitigation curve.

Fig. 22: Volumes and Lifetimes of industrial CO2 Use

Chemical Application	Annual Market (Mtpa)	CO2 used	Lifetime
UREA	129 Mt	65-70 Mt	6 months
Methanol	40 Mt	14 Mt	6 months
Inorganic Carbonates	8 Mt	3 Mt	decades to centuries
Organic Carbonates	2,6 Mt	0,2 Mt	decades to centuries
Polyurethanes	10 Mt	< 10 Mt	decades to centuries
Technological	10 Mt	10 Mt	days to years
Food	8 Mt	8 Mt	months to years

Sources: IPCC 2005

There is a clear indication that mineral carbonation and algae cultivation provide for substantial CO2 usage potentials, but for large scale application, the cost of applying these techniques would need to be considerably lowered.

Fig. 23: Volumes and Lifetimes of industrial CO2 Use (Case Studies)

CO2 Reuse Application	CO2 emitted per CO2 used (tCO2)	Carbon Abatement Potential	Scalability	Abatement Cost
Resulting in negative CO2 emissions (Carbon abatement option)				
Carbonate Mineralisation	0.32	68%	highest	high
Algae Cultivation	0.42	58%	high	high
Enhanced Geothermal	0.44	56%	low	medium
Enhanced Oil Recovery (EOR)	0.51	49%	high	low
Bauxite Residue Carbonation	0.53	47%	low	medium
Renewable Methanol (biogenic CO2)	1.00	medium, vs. Traditional fuel	low to medium	highest
Resulting in additional CO2 emissions (no Carbon abatement)				
Renewable Methanol (fossil CO2)	1.71	some, vs. traditional fuel	high	high
Concrete Curing	2.20	vs. traditional concrete	high	medium
UREA Yield Boosting	2.27	no	low	n.a.
Formic Acid	3.96	no	high	n.a.
Polymers	5.52	no	low	n.a.

Source: Inagendo Update of Edge 2011

As Edge 2011 is based on individual case studies, Figure 23 may only give a crude approximation of carbon abatement potentials. Renewable methanol and concrete curing lead to positive emissions, but are valid CO2 abatement venues, if compared to traditional non-captive production. In order to assess these potentials, the **life cycle emissions** from traditional vs. CO2 Reuse techniques would have to be analysed. Concrete curing can be considered a permanent CO2 sequestration option, as it firmly removes CO2 from the atmosphere. Significant CO2 abatement, thus, requires

- the use of CO2 provided by biogenic sources (such as biomass CCS),
- the reformation of CO2 to replace fossil fuels with a lower abatement potential, and
- the use of excess renewable energy to replace fossil fuels for the necessary process energy.

This being said, the abatement potential of industrial CO2 use is closely linked to using CO2 of biogenic origin and renewable energies. The IPCC's Special Report on CCS comes to a cautious assessment: *„The scale of the use of captured CO2 in industrial processes is too small, the storage times too short and the energy balance too unfavourable for industrial uses of CO2 to become significant as a means of mitigating climate change"* [IPCC 2005].

6. Conclusion

Carbon Capture and Use (CCU) and Carbon Capture and Cycling (CCC) are characterised by a broad portfolio of applications that do not provide for **permanent storage**, but may contribute to climate change mitigation by either offsetting CO2 from traditional production or by substituting fossil fuels. Carbon Capture, Use and Storage (CCUS) – in contrast - constitutes a viable carbon abatement option, since the CO2 is permanently removed from the atmosphere.

Most industrial uses, such as food treatment and chemical products, will remain low in scale, thus not processing significant amounts of CO2. UREA production is associated with additional CO2 emissions. Concrete curing and bauxite residue treatment offer considerable CO2 abatement potential, compared to traditional production. They also provide for permanent sequestration of CO2.

Enhanced oil recovery, enhanced coal bed methane, mineralisation, algae cultivation, and renewable methanol each could use significant amounts of CO2, in excess of 300 MtCO2pa. Of these applications, algae and renewable methanol come with no **permanent abatement**, unless they utilise CO2 from biomass. Mineralisation is the only application virtually unlimited in scale and retaining 100 percent of the CO2, but is associated with vast land use and high energy penalties, thus feasible only under excess renewable energy scenarios. Algae cultivation and renewable methane offer the potential to recycle large amounts of CO2 and substitute fossil fuels, but are yet immature techniques, associated with high costs. Algae cultivation may have some additional value in displacing traditional energy crops that are associated with detrimental environmental and societal by-effects.

Enhanced coal bed methane, enhanced oil recovery, and enhanced geothermal offer the additional benefit of releasing otherwise unrecoverable amounts of **incremental oil and methane**, providing for economic benefits in the range of several trillion US$. Of these applications, enhanced oil recovery is the only mature technology, proven in large scale commercial projects to date. Enhanced oil recovery also serves as a facilitator for large scale carbon capture and storage, at least offsetting some of the additional costs of CCS.

Given European applications, enhanced oil recovery offers significant benefits, both for European climate targets and for decreasing dependency on imported fuels. EOR has the potential to

- contribute 17.8 percent towards the EU-27 climate mitigation goal of 30 percent in 2030;
- increase domestic oil production to substitute foreign imports, thus taking 300-544 billion € off the EU's energy bill;
- facilitate the construction of a European CCS infrastructure, offsetting part of the CCS costs;
- develop offshore storage infrastructure, thereby decreasing public acceptance issues that come with onshore storage.

Appendix A: Global Large-Scale Integrated EOR Projects (as of October 2013) *

Status	Project	Site	Vol. CO2 (Mt)	Start Date	Type	Pipeline Length (km)
Operate	Air Products Steam Methane Reformer EOR	USA	1	2013	Hydrogen	101-150
Operate	Century Plant	USA	8,4	2010	Natural Gas	69
Operate	Coffeyville Gasification Plant	USA	1	2013	Fertiliser	112
Operate	Enid Fertilizer CO2-EOR	USA	0,7	1982	Fertiliser	225
Operate	Great Plains Synfuel Plant and Weyburn-Midale	CAN	3	2000	SynGas	315
Operate	Lost Cabin Gas Plant	USA	0,8-1,0	2013	Natural Gas	N/S
Operate	Petrobras Lula Oil Field CCS	BRZ	0,7	2013	Natural gas	Direct Injection
Operate	Shute Creek Gas Processing Facility	USA	7	1986	Natural Gas	403
Operate	Val Verde Natural Gas Plants	USA	1,3	1972	Natural Gas	132
Execute	Alberta Carbon Trunk Line ("ACTL") with Agrium CO2 Stream	CAN	0,4-0,6	2015	Fertiliser	240
Execute	Alberta Carbon Trunk Line ("ACTL") with North West Sturgeon Refinery CO2 Stream	CAN	1,2-1,4	2016	Oil Refining	240
Execute	Boundary Dam Integrated Carbon Capture and Sequestration Demonstration	CAN	1	2014	Power Gen.	100
Execute	Kemper County IGCC	USA	3,5	2014	Power Gen.	75
Execute	Uthmaniyah CO2 EOR Demonstration	Saudi Arabia	0,8	2014	Natural gas	70
Define	ESI CCS	UAE	0,8	2015	Iron & Steel	47
Define	Hydrogen Energy California (HECA)	USA	3	2018	Power Gen.	6,4
Define	Lake Charles Gasification	USA	4,5	2015	SynGas	N/S
Define	Medicine Bow Coal-to-Liquids Facility	USA	2,0-3,0	2016	Coal-to-liquids	N/S
Define	NRG Energy Parish CCS	USA	1,4-1,6	2016	Power Gen.	132
Define	PetroChina Jilin Oil Field EOR (Phase 2)	CHINA	0,8	2015	Natural Gas	35
Define	Sinopec Shengli Dongying CCS	CHINA	0,5	2015	Chemical	70
Define	Sinopec Shengli Oil Field EOR (Phase 2)	CHINA	1	2015	Power Gen.	51-100
Define	Texas Clean Energy	USA	2,0-3,0	2017	Power Gen.	<50
Evaluate	Bow City Power	CAN	1	2019	Power Gen.	51-100
Evaluate	Emirates Aluminium CCS	UAE	2	2018	Power Gen.	351-400
Evaluate	Huaneng GreenGen IGCC (Phase 2)	CHINA	2	2016	Power Gen.	51-100
Evaluate	Indiana Gasification	USA	5,5	2015	SynGas	>400
Evaluate	Kentucky NewGas	USA	5	2018	SynGas	N/S
Evaluate	Mississippi Gasification (Leucadia)	USA	3,0-4,0	2015	SynGas	176
Evaluate	Quintana South Heart	USA	2,1	2017	Power Gen.	N/S
Evaluate	Riley Ridge Gas Plant	USA	2,0-3,0	2017	Natural Gas	N/S
Evaluate	Yanchang Jingbian CCS (Phase 2)	CHINA	0,4	2016	Chemical	130
Identify	Lianyungang IGCC with CCS	CHINA	0,8-1,0	2019	Power Gen.	201-250

* Large Scale Integrated Projects (LSIP) are defined as projects storing more than 800 Megatons (for Power Generation projects) or more than 400 Megatons of CO2 (for industrial projects)

Source: GCCSI 2013cd

Appendix B: Abbreviations

bbl	Barrel
BOPD	Barrels of Oil per day
CBM	Coal Bed Methane
CCC	Carbon Capture and Cycling
CCS	Carbon Capture and Storage
CCTS	Carbon Capture, Transport and Storage
CCU	Carbon Capture and Use
CCUS	Carbon Capture, Use and Storage
CH4	Methane
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
CO2 ECBM	Enhanced Coal Bed Methane using Carbon Dioxide
CO2 EGR	Enhanced Gas Recovery using Carbon Dioxide
CO2 EOR	Enhanced Oil Recovery using Carbon Dioxide
CTL	Coal-to-Liquids
dH	Heat of Reaction
ECBM	Enhanced Coal Bed Methane
EGR	Enhanced Gas Recovery
EGS	Enhanced Geothermal Systems
EOR	Enhanced Oil Recovery
ETS	(European) Emission Trading System
GHG	Greenhouse Gas
Gt	Gigaton
GtCO2	Gigaton Carbon Dioxide
Gtpa	Gigatons per anno
ha	hectare (10,000 square meters)
IGCC	Integrated Gasification Combined Cycle
kJ/molCO2	Kilojoule per Mol of Carbon Dioxide
ktCO2	Kiloton Carbon Dioxide
LCA	Life Cycle Assessment
LSIP	Large-Scale Integrated Project
MAP	Modified Atmosphere Packing
MC	Mineral Carbonation
Mcf	Thousand cubic feet
MMbbl	Million Barrels
Mt	Megatonne
Mtpa	Megatons per anno
MtCO2	Megatonne Carbon Dioxide
MtCO2pa	Megatonne Carbon Dioxide per anno
NGO	Non Governmental Organisation
NSG	North Sea Graben
OOIP	Original Oil in Place
R&D	Research and Development
RES	Renewable Energy Sources
ROZ	Residual Oil Zone
SynGas	Synthetic Natural Gas
tCO2	Tonne Carbon Dioxide
Tm3	Trillion Cubic Meters
WTI	Western Texas Intermediate (Oil Price Index)

Appendix C: Sources

Alvarado, V. et al. (2010): Enhanced Oil Recovery: An Update Review, in: Energies 2010, 3, 1529-1575, www.mdpi.com/1996-1073/3/9/1529/pdf

API (2007): Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology, http://www.api.org/environment-health-and-safety/environmental-performance/~/media/d68de1954b8e4905a961572b3d7a967a.ashx

ARI (2010): Optimization of CO_2 storage in CO_2 Enhanced Oil Recovery Projects, *http://www.adv-res.-com/pdf/1006-optimization-of-CO2-storage-in-CO2-enhanced-oil-re.pdf*

ARI (2011): Global Technology Roadmap For CCS In Industry. Sectoral Assessment CO 2 Enhanced Oil Recovery, *http://www.unido.org/fileadmin/user_media/Services/Energy_and_Climate_Change/Energy_Efficiency/CCS/EOR.pdf*

Atlantic Council (2012a): US Policy Shift to Carbon Capture, Utilization, and Storage Driven by Carbon Dioxide Enhanced Oil Recovery, http://www.acus.org/files/publication_pdfs/403/CCUS-EOR%20(IB1)%2010-22.pdf

Atlantic Council (2012b): The Business Case for Carbon Capture, Utilization and Storage, http://www.a-cus.org/files/publication_pdfs/403/ee121022ccus.pdf

CSLFORUM (2012): Technology Roadmap 2011, http://www.cslforum.org/publications/documents/CSLF_Technology_Roadmap_2011.pdf

CFLCF (2011): Carbon Capture and Utilisation in the Green Economy, *http://www.policyinnovation-s.org/ideas/policy_library/data/01612/_res/id=sa_File1/CCU.pdf*

CCC (2012): Meeting the Carbon Budgets – 2012 Progress Report to Parliament, *http://archive.thec-cc.org.uk/aws/2012%20Progress/1585_CCC_Progress%20Rep%202012_Interactive.pdf*

DECC (2012): CCS Roadmap: Learning by Doing – Launching the CCS Commercialisation Programme, *https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48317/4899-the-cc-s-roadmap.pdf*

DECC (2013): UK Oil and Gas. Business and Government Action, https://www.gov.uk/government/up-loads/system/uploads/attachment_data/file/175480/bis-13-748-uk-oil-and-gas-industrial-strategy.pdf

DIW (2013): The Role of CO2-EOR for the Development of a CCTS Infrastructure in the North Sea Region. A Techno-Economic Model and Application, http://www.diw.de/documents/publikationen/73/diw_01.c.423587.de/dp1308.pdf

DOE (2010): Report of the Interagency Task Force on Carbon Capture and Storage, *http://www.fe.-doe.gov*

DVGW (2013): Analyse des Klimaschutzpotentials der Nutzung von erneuerbarem Wasserstoff und Methan, http://www.dvgw-innovation.de/fileadmin/dvgw/angebote/forschung/innovation/pdf/g8_01_11.pdf

Dumont et al. (2012): Assessing the Environmental Potential of Carbon Dioxide Utilization: A Graphical Targeting Approach, Proceedings of the 11th International Symposium on Process Systems Engineering, 15-19 July 2012, Singapore, http://orbi.ulg.ac.be/bitstream/2268/113461/1/DumontEtAl_PSE2012_EnvironmentalPotentialof-CO2Utilization.pdf

Edge Environment (2011): Life Cycle Assessment of Carbon Dioxide Re-Use Technologies, Appendix M to GCSSI 2011, http://cdn.globalccsinstitute.com/sites/default/files/spublications/14026/accelerat-ing-uptake-ccs-industrial-use-captured-carbon-dioxide.pdf

Element Energy et al. (2012): Economic Impacts of CO2-Enhanced Oil Recovery for Scotland, http://www.scottish-enterprise.com/~/media/SE/Resources/Documents/DEF/Economic%20Potential%20of%20CO2%20EOR%20in%20Scotland.pdf

European Commission (2011): Energy Roadmap 2050, COM(2011) 885 final, http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0885:FIN:EN:PDF

European Commission (2013): Public Consultation on: The Future of Carbon Capture and Storage in Europe, COM(2013) 180 final, *http://ec.europa.eu/energy/coal/doc/com_2013_0180_ccs_en.pdf*

Godec, M. et al (2011): CO2 Storage in Depleted Oil Fields: The Worldwide Potential for Carbon Dioxide Enhanced Oil Recovery, Energy Procedia 4 (2011) 2162–2169, http://dx.doi.org/10.1016/j.egypro.2011.02.102

GCCSI (2011): Accelerating the Uptake of CCS: Industrial Use of Captured Carbon Dioxide, *http://cdn.globalccsinstitute.com/sites/default/files/spublications/14026/accelerating-uptake-ccs-industrial-use-captured-carbon-dioxide.pdf*

GCCSI (2013a): Bridging the Gap: An Analysis and Comparison of Legal and Regulatory Frameworks for CO2–EOR and CO2–CCS, http://cdn.globalccsinstitute.com/sites/default/files/publications/118951/eor-report-2013-4-nov.pdf

GCCSI (2013b): Technical Aspects of Enhanced CO2 Oil Recovery and Associated Carbon Storage, http://cdn.globalccsinstitute.com/sites/default/files/publications/118946/technical-aspects-co2-enhanced-oil-recovery-and-associated-carbon-sto.pdf

GCCSI (2013c): Status of CCS Projects Update, October 2013, http://cdn.globalccsinstitute.com/sites/default/files/pages/41416/large-scale-integrated-ccs-projects-10-october-2013.xls

GCCSI (2013d): The Global Status of CCS 2013, http://cdn.globalccsinstitute.com/sites/default/files/publications/116211/global-status-ccs-2013.pdf

Gu, Yan (2013): Carbon Capture & Storage Policy in China, https://web.law.columbia.edu/sites/default/files/microsites/climate-change/files/Publications/Students/Yan%20Gu%20CCS%20Paper%20Final.pdf

Hill et al. (2013): Geologic Carbon Storage through Enhanced Oil Recovery, Energy Procedia 2013, forthcoming, http://www.catf.us/resources/publications/files/201301-Geologic_carbon_storage_through__enhanced_oil_recovery.pdf

Holt, T. et al. (2009): EOR and CO2 disposal — Economic and Capacity Potential in the North Sea, Energy Procedia, (1) 2009, pp. 4159–4166, http://dx.doi.org/10.1016/j.egypro.2009.02.225

ICO2N (2013): Net Greenhouse Gas Impact of Storing CO2 through Enhanced Oil Recovery (EOR), http://www.ico2n.com/wp-content/uploads/2013/06/Ico2n_EOR-Final-Report.pdf

IEA (2008): CO_2 Capture and Storage. A Key Carbon Abatement Option (Energy Technology Analysis), http://www.iea.org/publications/freepublications/publication/CCS_2008.pdf

IEA (2010): Energy Technology Perspectives 2010. Scenarios & Strategies to 2050, http://www.iea.org/publications/freepublications/publication/etp2010.pdf

IEA (2012a): Carbon Capture and Storage Legal and Regulatory Review, http://www.iea.org/publications/freepublications/publication/CCS_Review_3rdedition_FINAL.pdf.

IEA (2012b): Energy Technology Perspectives 2012. Pathways to a Clean Energy System

IEA (2012c): World Energy Outlook 2012

IEA (2013a): Redrawing the Energy-Climate Map. World Energy Outlook Special Report, http://www.iea.org/publications/freepublications/publication/RedrawingEnergyClimateMap_2506.pdf

IEA (2013b): Technology Roadmap: Carbon Capture and Storage, http://www.iea.org/publications/freepublications/publication/CCS_Roadmap.pdf

IEA (2013c): Tracking Clean Energy Progress. IEA Input to the Clean Energy Ministerial, http://www.iea.org/publications/freepublications/publication/TCEP_web.pdf

IEA GHG (2009): CO_2 Storage In Depleted Oilfields: Global Application Criteria For Carbon Dioxide Enhanced Oil Recovery, *http://www.ieaghg.org/docs/General_Docs/Reports/2009-12.pdf*

IEA GHG (2012): CO_2 Capture at Gas Fired Power Plants, *http://www.ieaghg.org/docs/General_Docs/Reports/2012-08.pdf*

Inagendo (2009): Carbon Capture and Storage (CCS). Chancen und Risiken der Kohlendioxidabscheidung und -speicherung, http://www.energie-fakten.de/pdf/ccs-inagendo-v10.pdf

IPCC (2005): Special Report on Carbon Dioxide Capture and Storage, *http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf*

IWES (2011): Energiewirtschaftliche und ökologische Bewertung eines Windgas-Angebotes http://www.greenpeace-energy.de/fileadmin/docs/sonstiges/Greenpeace_Energy_Gutachten_Windgas_Fraunhofer_Sterner.pdf

Kemp, A.G. et al. (2012): The Economics of CO2-EOR Cluster Developments in the UK Central North Sea/ Outer Moray Firth ' North Sea Study Occasional Paper , no. 123, http://hdl.handle.net/2164/2379

Kuuskraa, V.A. (2012):Using the Economic Value of CO2-EOR to Accelerate the Deployment of CO2 Capture, Utilization and Storage (CCUS), http://www.globalccsinstitute.com/publications/proceedings-2012-cost-workshop/online/116846

Koottungal, L (2012): Special Report 2012: Worldwide EOR Survey, Oil and Gas Journal, April 2, 2012), http://www.ogj.com/articles/print/vol-110/issue-4/general-interest/special-report-eor-heavy-oil-survey/2012-worldwide-eor-survey.html

Leach, A. et al. (2010): Co-optimization of EOR and Carbon Sequestration", Smith School Working Paper series 005, *http://www.smithschool.ox.ac.uk/wp-content/uploads/2010/02/Mason_online.pdf*

Melzer, L. S. (2012); Carbon Dioxide Enhanced Oil Recovery (CO2 EOR): Factors Involved in Adding Carbon Capture, Utilization and Storage (CCUS) to Enhanced Oil Recovery, http://neori.org/Melzer_CO2EOR_CCUS_Feb2012.pdf

MITEI (2010): Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration, *http://mitei.mit.edu/system/files/110510_EOR_Report_1.pdf*

NCC (2012): Harnessing Coal's Carbon Content to Advance the Economy, Environment, and Energy Security, *http://www.nationalcoalcouncil.org/reports/07-10-12-NCC_Harnessing_Coals_Carbon_Content_to_Advance_Economy_Environment_EnergySecurity.pdf*

NDRC (2013): Notice of National Development and Reform Commission (NDRC) on Promoting Carbon Capture, Utilisation and Storage Pilot and Demonstration, No. 849, http://cdn.globalccsinstitute.com/sites/default/files/publications/102106/notice-national-development-reform-commission-ndrc.pdf

NEORI (2012): Carbon dioxide enhanced oil recovery: A critical domestic energy, economic and environmental opportunity, *http://www.neori.org/NEORI_Report.pdf*

NETL (2010a): Carbon Dioxide Enhanced Oil Recovery. Untapped Domestic Energy Supply and Long Term Carbon Storage Solution, http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_EOR_Primer.pdf

NETL (2010b): Storing CO2 and Producing Domestic Crude Oil with Next Generation CO2-EOR Technology: An Update, http://www.netl.doe.gov/energy-analyses/pubs/StoringCO2NexGenEOR10.pdf

NETL (2011): Improving Domestic Energy Security and Lowering CO 2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR), http://www.netl.doe.gov/energy-analyses/pubs/NextGen_CO2_EOR_06142011.pdf

Oei, P.Y. et al. (2013): Development Scenarios for a CO2 Infrastructure Network in Europe, http://www.uni-potsdam.de/fileadmin/projects/wipo/Projekt_RM/WP_RM_36_Oei_Mendelevitch_2013_CO2_Infrastructure_Europe.pdf

PTRC (2011): Peer Review of Soil Gas Chemistry Report, http://www.cenovus.com/operations/oil/docs/PTRC.pdf

SCCS (2009): Opportunities for CO2 Storage around Scotland, http://www.scotland.gov.uk/Resource/Doc/270737/0080597.pdf

SCCS (2013): Unlocking North Sea CO2 Storage for Europe: Practical Actions for the Next Five Years, http://www.sccs.org.uk/expertise/SCCSConference2013Report.pdf

SBC (2011): Leading the Energy Transition. Bringing Carbon Capture & Storage to Market, *http://www.sbc.slb.com/SBCInstitute/Publications/~/media/Files/SBC%20Energy%20Institute/SBC%20Energy%20Institute_Bringing%20CCS%20to%20Market1.ashx*

Tzimas, E. et al. (2005): Enhanced Oil Recovery using Carbon Dioxide in the European Energy System, http://science.uwaterloo.ca/~mauriced/earth691-duss/CO2_General%20CO2%20Sequestration%20materilas/CO2_EOR_Misciblein%20Europe21895EN.pdf

Tzimas, E. et al. (2006). CO_2 Storage Potential in the North Sea via Enhanced Oil Recovery, *http://www.CO2.no/download.asp?DAFID=55&DAAID=4*

USCSC (2012): An Early Deployment Strategy for Early Carbon Capture, Utilization, and Storage (CCUS) Technologies, http://www.uscsc.org/Files/Admin/Educational_Papers/20120604_Early%20Deployment%20Strategy%20for%20CCUS%20Technologies_FINAL.pdf

Zimmer, M. et al. (2011): Long-term Surface Carbon Dioxide Flux Monitoring at the Ketzin Carbon Dioxide Storage Test Site, Environmental Geosciences, 2(2011), pp. 119-130, http://dx.doi.org/10.1306/eg.11181010017

Web Resources:

Berlin (2013): 3. Statuskonferenz zur BMBF-Fördermaßnahme "Technologien für Nachhaltigkeit und Klimaschutz - Chemische Prozesse und stoffliche Nutzung von CO2", Berlin, 9-10 April 2013, *http://www.chemieundco2.de/de/317.php*

Brussels (2012): CO2 Reuse Technologies. Workshop on Innovation and Climate Policy, Brussels, 24 October 2012, http://www.co2reuse.eu/workshop.html

Essen (2013): 2nd Conference on Carbon Dioxide as a Feedstock for Chemistry and Polymers, Essen, 7-9 October 2013, *http://co2-chemistry.eu/media/CO2_proceedings_2013.zip*

US Energy Information Administration: International Energy Statistics, http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=90&pid=44&aid=8