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Report

CCS status – Input to the CSLF Technology Roadmap 2013

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ABSTRACT
The Carbon Sequestration Leadership Forum (CSLF) Technical Group has decided to update its Technology Roadmap from 2011 and to present this new roadmap at the 5th CSLF Ministerial Meeting in Houston, USA in November 2013. Norway has taken the editorial and coordinating responsibility for the new roadmap. A steering committee ensures review, contributions and recommendations from the rest of the Technical Group.

SINTEF has been engaged by the editor to contribute with the present CCS status report as a background document for the roadmap. The report summarizes the status with respect to large scale CCS demonstration projects and the technological status of the different parts of the CCS chain (capture, transport and storage). Included is also CCS in industrial application and the use of CO_2 for enhanced oil recovery (EOR). The most important technological barriers for large-scale deployment of CCS are discussed, as well as the most significant technological aspects that can really reduce those barriers.

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1 Introduction

1.1 Background

In the 2 °C Scenario (2DS) of the IEA Energy Technology Perspectives 2012 [1], a total cumulative mass of 123 Gt CO_2 will be captured and stored from fossil power generation and industrial applications between 2015 and 2050. To reach this, the total annual global storage rate has to amount to 2.4 Gt/year in 2030, and 7.8 Gt/year in 2050. The industrial applications of carbon capture and storage (CCS) will be almost equally important as CCS in the power generation sector in order to fulfil the scenario.

In comparison; the total capture capacity of the large-scale integrated CCS projects (LSIP's) in operation is about 0.023 Gt/year and the capacity of plants under construction is about 0.014 Gt/year [2]. Most of these projects have enhanced oil recovery (EOR) as the primary storage option and the net CO_2 reduction may be lower than what is actually captured and stored.

At the 2011 Ministerial-level CSLF meeting in Beijing, P.R. China, it was agreed to include "utilization" of CO_2 as a means of reducing anthropogenic CO_2 emissions. In the present document the technologies behind the term "utilization" are not appropriately defined except some specific sections and paragraphs. For this reason the term CCS will be mostly used in this report.

About two-thirds of the world's electricity production is being generated from fossil fuels. Even though non-fossil electricity generation is increasing, it is more than outweighed by the increase in coal use. Coal is the energy source that increased the most during the last ten years, producing about 40% of world electricity in 2009. Coal is and will be the major fossil energy source the coming decades, contributing the largest emissions and being the most important one for CCS. There was more than 1,600 GW installed capacity in 2010, emitting almost 9 Gt/year of CO_2, and coal power generation is expanding faster than ever.

The cumulative emissions from the coal power plants already in place and those under construction will be more than 590 Gt by 2035 [1]. Retrofit of CCS will likely be needed to reduce the global effect of these emissions. The larger and more modern and efficient plants are best suited for retrofitting. Today there are installed about 470 GW generation capacity in coal-fired plants larger than 300 MW and not older than 10 years. Most of these are in China which has the overall most modern coal-fired power generation plants.

In 2030 the global electricity generation will be almost 9,000 GW and in 2050 it will be 12,000 GW. Of this, in the 2DS, power stations equipped with CCS will contribute about 280 GW in 2030 and 960 GW in 2050. Of the 960 GW equipped with CCS in 2050 coal contributes the highest share; about 630 GW. Gas power plants is estimated to contribute 280 GW and the remaining 50 GW equipped with CCS will be on biomass power plants.

CCS will be an important mitigation option in the long term but it has to be further developed from the present status, which is shortly summarized by IEA [1]: "Some CO_2 capture technologies are commercially available today and the majority can be applied across different sectors, although storage issues remain to be resolved. While most (CCS technologies) remain capital-intensive and costly, they can be competitive with other low-carbon options. Challenges lie in integrating these technologies into large-scale projects"[1].

1.2 Barriers for large-scale project deployment

The G8 has targeted 20 large integrated CCS demonstration projects operating worldwide by 2020. This goal can be seen as a component of a transition strategy calling for international actions to mobilise knowledge and capacities to fast-track CCS as a viable option for mitigating climate change. In a carbon-constrained context, this is achieved by trapping the CO_2 and preventing it from reaching the atmosphere. Technically, CCS consists of three operational components: a) CO_2 capture and compression, b) CO_2 transport and c) CO_2 storage. Each component is essential for the demonstration and deployment of a full CCS chain.

Key barriers to CCS deployment are economic, financial, legal, and regulatory uncertainty, as well as public awareness and support. Technology development can help address these barriers as well as provide the assurance of CCS being a safe, permanent, and effective option for reducing greenhouse gas emissions.

Commercially, CCS implementation implies activities such as: a) preparation, b) feasibility study, c) appraisal and permitting, d) design and construction (implementation), e) operation and monitoring, and, beyond the operational phase, f) closure and g) post-closure management. The entire lifespan of a CCS project is much longer than that of comparable projects. Studies suggest that geological storage – especially in saline formations – requires evidence for the CO_2 to be kept safely in the subsurface for several thousand years [3]. Hence, the liability of commercial CCS projects is an issue that remains to be resolved. This calls for a predictable legal and regulatory framework, and institutional mechanisms for the approval, permitting and abandonment of CCS projects.

Moreover, in mitigating climate change, time, capacity and funding are critical factors. Public money for pilot projects and demonstration projects is a key prerequisite to accelerate and understand the integrated technical and non-technical processes that are required in order for CCS to reach the stage of transition and implementation. Before CCS can be deployed on a large scale, the major barriers must be removed, and all actions must be sufficiently understood. And, last but not least, technologies must be verified through demonstration and, eventually, proved to be safe and successful in a commercial setting.

1.3 Cost and maturity

CCS is already being applied in some parts of the world. For example, the Sleipner and In Salah projects are capturing CO_2 from natural gas processing facilities and injecting it into saline formations to demonstrate CO_2 storage. In the United States, the utilization of CO_2 for enhanced oil recovery (EOR) has been underway for over 40 years at more than 110 operations (referred to as carbon capture, utilization, and storage - CCUS). While a large portion of the CO_2 used for EOR in the United States is from natural CO_2 sources, several anthropogenic sources – natural gas processing and ethanol plants, for example – are supplying CO_2 for EOR purposes.

At present the "U" is also seen as the main driver in China for large-scale CCUS demonstration projects. This particularly applies to EOR, although several plants produce food-grade CO_2 for the beverage industry, and one large demonstration plant is being built using CO_2 for micro-algae biodiesel production [4]. While EOR does offer a potential market incentive for the capture, utilization, and storage of CO_2, wide-scale commercial deployment of CCS from power plants without this revenue stream will require appropriate public and private funding to sustain a complementary chain of actions from research and technology development through semi-commercial demonstration to firm operations by first-movers.

Hitherto, significant efforts have been spent on capture techniques and geological mapping in order for CCS operations to get started. Main barriers to CCS deployment are high capital costs and energy-penalty, as well as uncertainty about the market and long-term liability – combined with insufficient public support and even distrust. Furthermore, as risk generally affects the cost, proper technology development must be ensured, including testing, demonstration and verification.

Whereas CO_2 capture is, by far, the most costly and energy-intensive component of the CCS chain, qualification of storage sites in most cases appears to constitute the critical path and so far has proved to be the lengthiest in terms of site identification, selection, characterisation and permitting. It is expected that storage will also determine the pace of CCS deployment in some regions. This is a plight that calls for extended targeted research and development actions across nations. Experience tells us that typically it takes 7-12 years to qualify a new saline formation for CO_2 storage. For projects using depleted oil and gas reservoirs, the lead time may be shorter because of the pre-existence of significant amounts of data and knowledge about these reservoirs. Different technical issues may, however, arise, for instance the number and age of the wells in the field. Relevant questions are whether all the wells are located, is the status of the cement job known, and are aquifers intersected? The storage capacities in depleted oil and gas reservoirs are usually not as great compared with saline formations and ultimately they are insufficient to achieve 2050 emission reduction targets.

Today, all large-scale integrated projects in the operation and construction phase as well as most pilot and demonstration projects represent first generation CCS technology. Future research actions must build on current knowledge and experience gained, aimed at:

- Reducing cost and energy penalty of CO_2 capture
- Reducing risks and ensuring safety of the CCS chain as projects grow in scale
- Developing new second generation and third generation CCS technology (aiming at 2030 and beyond, respectively).

The scale of research will have to increase in order to overcome technology barriers within the required timeframe and according to the preferential commercial size.

2 Status on integrated large-scale CCS demonstration projects

The following status on large-scale integrated CCS projects (LSIP's) is mainly a summary of the Global CCS Institute (GCCSI) Global Status of CCS 2012 including the update of January 2013 [2]. Other listings and project surveys exist (CSLF, DoE/NETL, IEAGHG) but the GCCSI listing is currently the most up to date.

The definition of a LSIP by GCCSI is that it involves a complete chain of capture, transport and storage of:

- at least 800,000 tonnes per year for coal-based power plants
- at least 400,000 tonnes per year for other plants, including gas-based power plants.

In the latest Global Status report [2], GCCSI has identified in total 72 LSIP's. This is a net decrease of two projects since the 2011 inventory. Nine new projects have been added while 11 projects have been removed from the 2011 LSIP listing because they have been cancelled or put on hold. The reasons for cancellation or putting the projects on hold are mainly related to cost and insufficient funding but lack of CCS legislation was also blamed in two projects.

GCCSI uses an "Asset Lifecycle Model" to group the projects according to their development stage. This model has the following steps (in parenthesis is given the number of projects within the respective group):

- Identify: Concept studies to generate a short-list for further study. (14 projects)
- Evaluate: Pre-feasibility study to select one best option. (22 projects)
- Define: Feasibility study to make investment decision possible. (19 projects)
- Execute: Project execution, i.e. construction and commissioning. (9 projects)
- Operate: Operation of the project. (8 projects)

The eight projects in operation and the nine projects in the execute category (under construction) have a total capture capacity of approximately 0.023 Gt/year and 0.014 Gt/year, respectively [2]. In total 0.037 Gt/year. Most of these 17 projects are related to capture from industrial applications such as natural gas processing. Only two of them capture CO_2 from power generation plants. These two projects are the Boundary Dam CCS project in Canada and the Kemper County IGCC Project in the United States. Investment decisions have been made for both projects, and construction work has commenced.

Most projects have EOR as the primary storage type, for which the net CO_2 reduction may be lower than what is actually captured and stored. Of the total 36 projects in the Operate, Execute and Define categories, 22 are for EOR use of the captured CO_2.

USA and Canada dominates the first part of the list, i.e. the more developed projects. There is a domestic demand for CO_2 for EOR. For example, the NRG Energy Parish CCS Project was initially looking for a capture of 375,000 tonnes per year but the project was expanded to 1.6 million tonnes per year in response to the larger needs in EOR operations. In addition to the possible commercial use of the CO_2, several of the US projects have also got large governmental funding through the US Department of Energy (DOE) Clean Coal Power Initiative and the American Recovery and Reinvestment Act (ARRA). Shell Canada has received regulatory approval and is in the design and construction phase of its Quest project intended to store 1 Mt CO_2/year captured from an oilsands upgrader into a deep saline aquifer.

The Gorgon Carbon Dioxide Injection Project in Western Australia is also in the execute category. In October 2012, Australia's energy minister announced that the Gorgon project was still on track for injection to start in 2015 as planned. It will be the first in Australia and the world's largest sequestration project. Capture of CO_2 is from a larger gas production and LNG processing plant where about 4 Mtpa will be captured, transported and injected in a deep saline formation. Chevron and its joint venture partners have made a $2 billion investment in the injection project. The project satisfied some of the world's most stringent environmental impact assessment conditions in order to receive approvals. There are also plans for two other projects in Australia (South West Hub and CarbonNet) and one in New Zealand.

China has projects no higher than in the Evaluate category, where they have two projects according to GCCSI. However, China dominates the Identify category where it has nine projects and may be in a position to achieve really significant steps forward if the projects will progress as intended. The Energy Policy paper of X. Lai et al. from 2012 [5] summarizes a total of 20 Chinese CCS demonstration projects, both small and large. The large scale projects on this list do only partly match the GCCSI list and the status reported by X. Lai et al. seems to be that the projects have progressed further than specified by GCCSI.

The European Commission, together with the European Investment Bank and EU member states, jointly operate the NER300 financing competition in which governments can shortlist renewable and CCS projects for European subsidies. Under the first call there were eight candidate CCS projects plus two on the reserve list. The European Commission published, on 18 December 2012 [6], the list of projects eligible for funding. The Commission found that none of the CCS projects met all the necessary criteria. Efforts are now made to accelerate the second call.

United Arab Emirates and Korea and several other countries are also on the list with plans for large-scale integrated CCS projects.

Key points

Most large-scale integrated projects in operation or under construction are related to natural gas processing and industrial hydrocarbon processes, and the captured CO_2 is used mainly for EOR. Thus, the net amount stored will be considerably lower than the total amount injected because of CO_2 production at production wells and recycling. Nevertheless, EOR still represents a highly important step in that projects related to power generation and CO_2 storage in deep saline formations must advance more rapidly than today.

3 CO_2 capture and integration into power generation plants

Today, in consideration of fossil-fuelled power cycles, three CO_2 capture technologies prevail; pre-combustion (IGCC- or IRCC-CCS [1]), oxy-combustion and post-combustion capture, as presented in Table 1. The readiness of these first generation technologies is indicated in the table, with reference to power generation using solid fuels (coal) and natural gas. In the two right-hand columns, the development potential of these technologies is identified for coal and natural gas, however, on a rather coarse basis.

Table 1: Readiness and development potential of main CO_2-capture techniques (from [7]).

	Readiness for application in first generation CCS schemes		**Development potential (next generation schemes)**	
Technology	Coal	Natural gas	Coal	Natural gas
IGCC-CCS	Medium-High	N/A	High	N/A
IRCC-CCS	N/A	High	N/A	Low
Oxy-combustion	Medium-High	Low	High	Medium-High
Post-combustion	High	High	Medium-High	Medium-High
	Generally, first generation technologies (state of the art), i.e. based mostly on techniques that are known and applicable today.		Second generation technologies to be due for application around 2030.	
			Third generation technologies to be due for application beyond 2030.	

The Integrated Reforming Combined Cycle (IRCC) will not be discussed further here due to the anticipated low efficiency compared to its reference process; a NGCC with post combustion capture. Possibly, natural-gas based pre-combustion technologies should rather focus on hydrogen production with CO_2 capture.

3.1 IGCC-CCS, pre-combustion techniques

Integrated gasification of coal with a combined power cycle (IGCC) and CCS is an emerging technique with a high development potential. Main components and characteristics of the system are depicted in Figure 1 and summarised in Table 2.

First generation technology comprises a conventional cryogenic air separation unit (ASU), which, owing to the limited amount of CO_2 needed for the gasification system, is deemed commercially available at preferential size. Absorption will usually be physical due to the high partial pressure of the shifted producer gas, but chemical absorption and adsorption techniques may also be used for this purpose.

Among second generation techniques, efforts are required in order to provide oxygen for the gasifier via membranes, and separation of the shifted producer gas into hydrogen and CO_2 may possibly require high-temperature membranes to be developed, validated and verified. It is widely accepted that a huge gap remains to be filled in order to scale up membrane systems from laboratory scale to commercial size. New

[1] IGCC / IRCC: Integrated Gasification (for coal) / Reforming (for natural gas) Combined Power Cycle.

gas turbines will be required in order to make use of the hydrogen-rich fuel gas leaving the separation unit in a more efficient way, without the need for the large volume of diluent flows of nitrogen and/or steam.

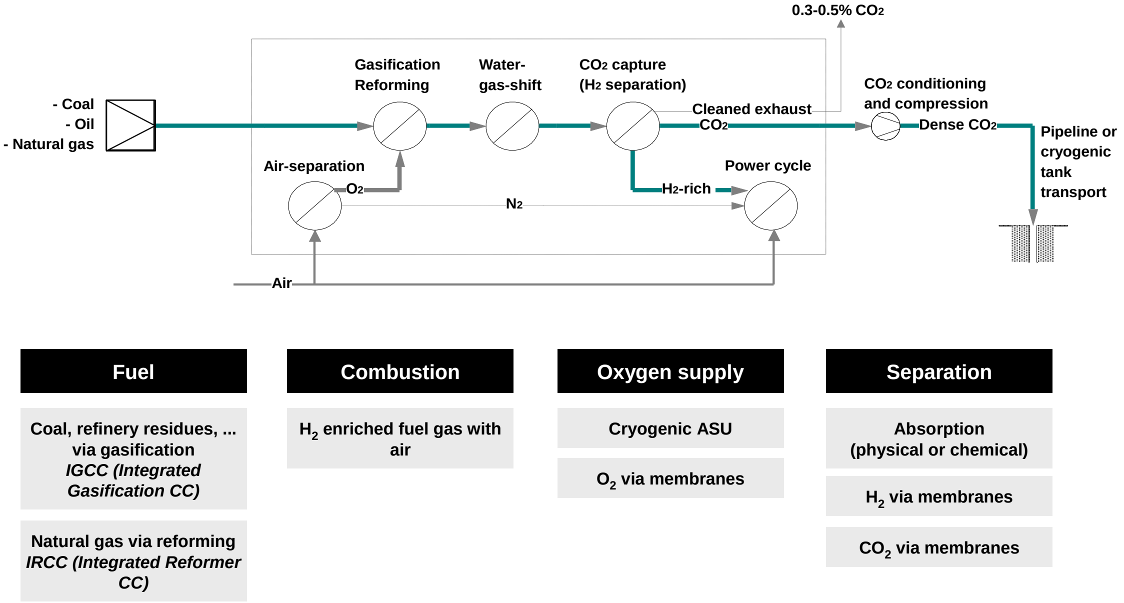


Figure 1: Main components of a typical IGCC-CCS power cycle. (Natural gas is shown as fuel option but IRCC is not seen as being that relevant for power production, as discussed below Table 1).

Table 2: Brief description of pre-combustion CO_2 capture technologies (IGCC-CCS)

	Pre-combustion (IGCC-CCS)
Technology description	Separation of CO_2 at high pressure from a shifted syngas (rich in CO_2 and H_2). The fuel is decarbonised and the hydrogen-rich gas diverts to a gas turbine topping cycle. Whereas gasification requires oxygen from ASU, the main oxidant is provided by air via the gas turbine (reacting with H_2). The nitrogen from the ASU is used for dilution/cooling of the gas turbine.
CO_2 treatment	Physical absorption. Both solvents and solid sorbents are potential options.
Key technology status / availability	Several operational IGCC plants around the world (e.g. Buggenum, Puertollano, GreenGen phase I&II). No integrated CCS system as yet. Semi-scaled demonstration not feasible owing to suitability and size of heavy-duty gas turbines. No (commercial) guarantee for IGCC-CCS available from suppliers.
Challenges	• Only full-sized demonstration (owing to the availability of gas turbines) • Degree of integration of large IGCC plants versus flexibility • Operational availability with coal in base load • Capital and operating costs • Lack of readiness (so far) to raise the commercial guarantees needed for large IGCC-CCS plants • Development of hydrogen-burning gas turbines with low NOx emission
Main features	Typical CO_2 concentration around 40% (pressure around 30 bar). Offers a high development potential owing to the combined power cycle. Lower demand for oxygen compared with oxygen-based combustion schemes, as only a smaller amount is needed for the auto-thermal oxidation in the gasifier.

Comprehensive research is required in order for IGCC-CCS to benefit from its theoretical potential. Improvement of efficiency and cost can be achieved by pursuing the following directions:

1. Development enabling modern high-efficient gas turbines to burn hydrogen
2. Integration of the ASU and the gas turbine
3. Economy of scale
4. Localisation issues
5. Availability
6. Polygeneration (optional swing producer)

(1) *Hydrogen combustion*. In order to benefit from the topping cycle, gas turbines capable of burning a hydrogen-rich fuel with low-NOx emissions are required. Eventually, plausible concepts should allow for only a small amount of dilution with nitrogen and steam, as required to cool hot spots.

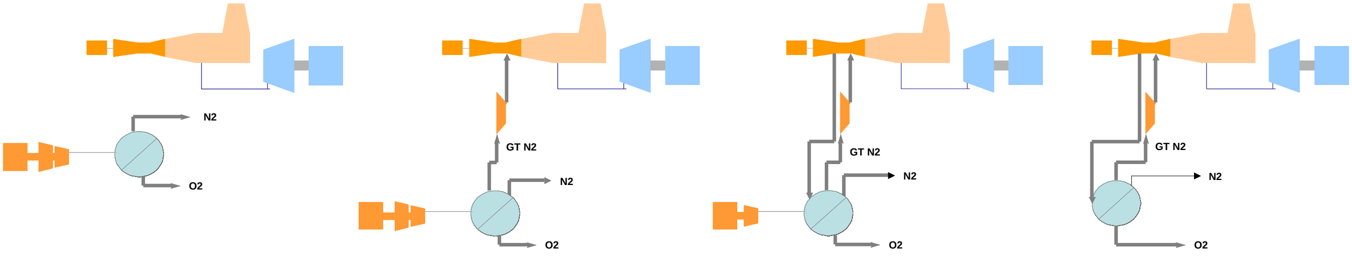
(2) *Integration of the ASU and the gas turbine*.This is an area of significant potential for improving the cycle performance and net efficiency. The challenge is the overall optimisation, especially the balancing of efficiency, costs and flexibility (cf. Figure 2**)**.

(3) *Economy of scale*. Policies and incentives are needed to accelerate the development, which apply to most emerging CCS technologies, especially via pilots and demonstrators. As shown in Figure 3, the expected achievements are quite high when diffusion is combined with technology development.

(4) *Localisation* of the plant. This direction may have a significant impact on the unit investment cost, the cost of CO_2 avoided, and, hence, also the levelised cost of electricity (cf. Figure 4). Hence, localisation of technologies, efficiency improvement and reduction of production costs are all important factors in order to understand the full cost picture. As IGCC-CCS inherently possesses a higher development potential than conventional pulverised-coal power cycles, gasification processes are seen as a future contender to the latter.

(5) *Availability* of IGCC-CCS plants. The number of hours these plants operate at rated power per year, is usually lower than that of alternative steam cycles. Significant research needs apply mainly to the gasifier design. Under this direction, technology improvements are also foreseen in the water-gas-shift reactor and the CO_2/H_2 separation unit. The latter will be based initially on sorption techniques (first generation CCS technology) and later possibly on membranes (second generation technology).

(6) *Polygeneration*. This is mainly to allow operations of the gasifier at base load (cf. Figure 5). In this context, the production of synthetic fuels (either hydrogen or methanol) can be seen as a swing producer offsetting the varying electric power demand over day, week and season.



No integration	Partial integration without gas turbine air	Partial integration with gas turbine air	Full integration
Advantages: ▪ high reliability due to independent operation mode ▪ highly flexible oxygen production ▪ guaranteed oxygen production even if GT trips (provided independent power supply)	Advantages: ▪ high reliability due to independent air supply mode ▪ highly flexible oxygen production ▪ production guaranteed even if GT trips (provided independent power supply) ▪ Improved specific energy demand ▪ Increased power from GT	Advantages: ▪ high reliability due to partial air supply by GT (normally no ASU trip if GT trips) ▪ highly flexible oxygen production ▪ other products than “GT N_2” guaranteed in lower quantity and lower purity even if GT trips ▪ improved specific energy demand ▪ lower air compressor investment	Advantages: ▪ ASU reliability is in general superior to that of the GT ▪ best specific energy demand due to higher valorisation of the feed components and lowest compression cost ▪ no main air compressor investment
Disadvantages: ▪ higher ASU investment	Disadvantages: ▪ Higher ASU investment ▪ N_2 compressor investment	Disadvantages: ▪ complexity ▪ air pressure variations ▪ N_2 compressor investment ▪ other products than “GT N_2” guaranteed in lower quantities (and purity) even if GT trips	Disadvantages: ▪ complexity ▪ if GT trips ASU trips ▪ if GT trips gasifier trips (or oxygen buffer tank is required) ▪ N_2 compressor investment ▪ ASU start-up time higher than GT ▪ potential start-up difficulties due to full integration (dual-fuel GT may help)

Figure 2: The impact of integrating ASU with IGCC [8].

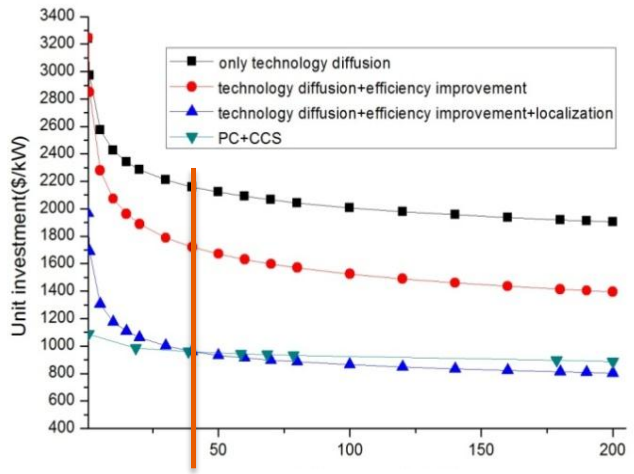


Figure 3: Investment cost of IGCC-CCS as a function of diffusion (i.e. number of plants), efficiency improvements and localisation compared with conventional post-combustion technologies.

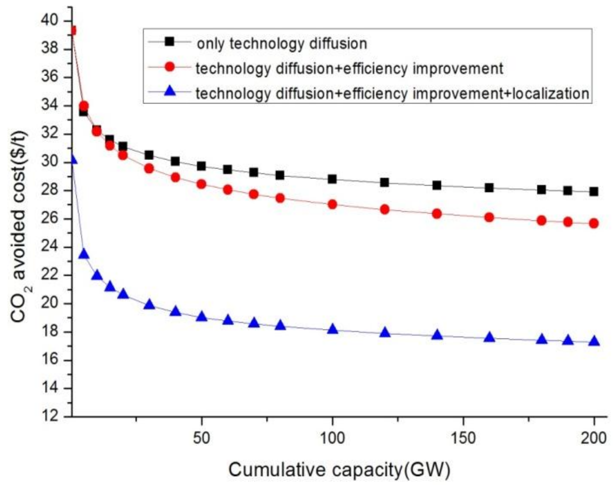


Figure 4: Estimated cost of CO_2 avoided of an IGCC-CCS plant as a function of diffusion (i.e. number of plants), efficiency improvements and localisation in a Chinese context.

(Courtesy: Institute of Engineering Thermophysics, China Academy of Sciences, 2010)

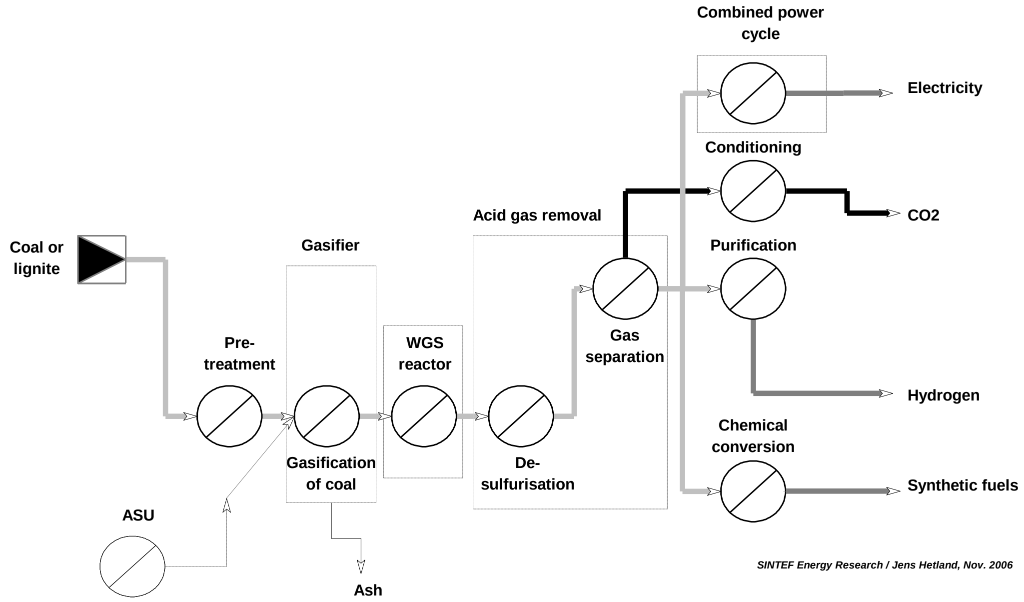


Figure 5: Polygeneration from coal broken down in unit operations [9].

Interesting features of integrated coal gasification with combined cycle (IGCC) are the enhanced efficiency and the low amounts of conventional pollutants and trace metals ([9], [10], [11]). It is expected that polygeneration may extend the range of applicable solid fuel qualities, including sulphur-rich coals. Furthermore, by co-producing coal-derived synthetic fuels, polygeneration may also respond significantly to the issue of security of energy supply.

IGCC-CCS systems with access to natural gas enables early operation, as the plant can start delivering electric power from an independent natural gas combined cycle (NGCC) long before the IGCC part has been completed. It also leaves the option to optimise operational expenses depending on the price of coal versus natural gas. Finally the concept may also extend the time-based availability from typically around 85-86% – as planned with some advanced IGCC projects – to well beyond 90% with natural gas.

3.2 Oxy-combustion capture techniques

Power cycle concepts using oxygen-based combustion are considered to have a high development potential which can only be validated via R&D and appropriate testing. Most oxy-combustion studies are steam-based power cycles as depicted in Figure 6, and further characterised in Table 3. In these cycles, the turbine working fluid is steam produced in oxy-combustion boilers. Another option is oxy-combustion gas turbine cycles where the oxygen is diverted to the combustion chamber of a gas turbine, whereby the hot reaction products form the working fluid to be expanded through the turbine.

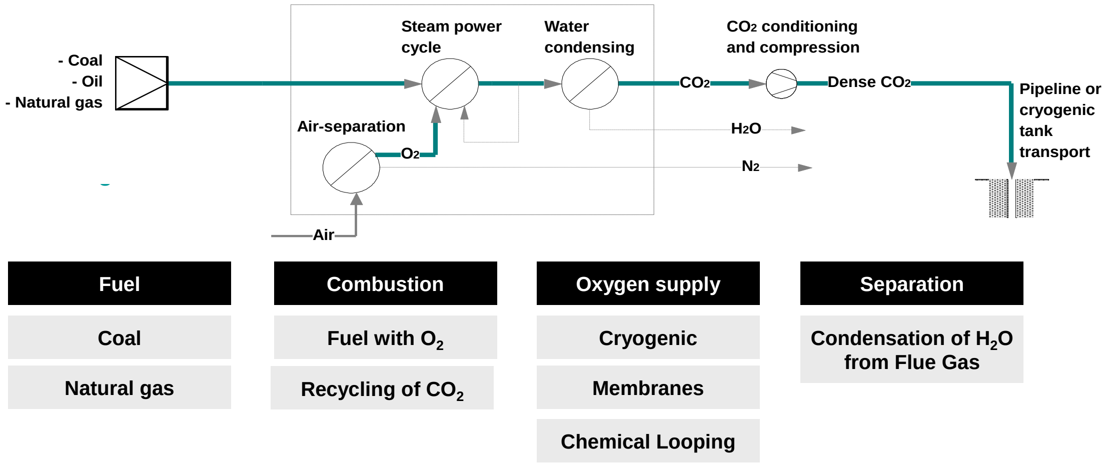


Figure 6: Typical oxy-combustion scheme

First generation technology is generally understood to comprise a versatile boiler system that may operate in dual mode (i.e. alternating between oxy-combustion and air-combustion). Due to the large oxygen demand of commercially-sized power plants, oxygen must be provided by multiple air separation units. Furthermore, in order to keep control of the furnace temperature, recycling of flue gas (CO_2) is required.

Second generation techniques are focused on developing alternatives to large and costly air separation units, such as technologies that separate oxygen from air via membranes, or on transformational technologies such as chemical looping. Furthermore, boiler systems will be tailor made for the smaller gas flow, and optimised for the actual flue gas composition (mainly CO_2 and H_2O). The rate of recirculated CO_2 will be minimised in order to improve efficiency. Gas turbine oxy-combustion schemes will be developed, thus allowing clean and efficient mechanical drives for industrial purposes, and oxygen-based topping cycles in new power cycle schemes.

Table 3: Brief characteristics of oxygen-based combustion capture concepts

	Oxygen-based combustion
Technology description	Oxygen (instead of air) is used as oxidant and the combustion leaves a flue gas rich in CO_2. Large amounts of oxygen require cryogenic air separation (ASU). Usually, the nitrogen from the ASU is vented to the surrounding air, as the concept does not make use of the nitrogen. Smaller flow paths combined with compact heat exchanger design due to lower mass flow of flue gas and high content of CO_2 and water.
CO_2 treatment	Cryogenic purification of the CO_2 stream prior to compression (if appropriate) – depending on specification of the CO_2 for the transport system (pipeline) or storage site.
Key technology status / availability	Small-scale pilot plants around 30 MW are operational (since 2008) in support of R&D. Mostly for pulverised coal and lignite, but also natural gas (Lacq, France). Growing interest for oxy-coal in CFB (circulating fluidised bed) technology. Also pressurised combustion is gaining interest.
Challenges	• High capital expenses and high operating costs • Unit size and capacity combined with the cost and exergy demand for cryogenic air separation (ASU) • Peak temperatures versus flue-gas re-circulation • NOx formation • Corrosion in CO_2 compression and purification unit (CPU) and transport lines • Optimisation of overall compressor work (ASU and CPU require compression work) • Lack of commercial guarantees
Main features	High concentration of CO_2 (typically >90%) and high content of water vapour in the flue gas. Possibility for knocking out water from the flue gas for use as process water.

The development potential of oxy-combustion systems inherently relates to the internal boiler design. Because of the lower gas volumes and the higher concentration of CO_2 and water vapour that enhances the component of radiative heat transfer, the heat exchanger areas can be significantly reduced. Other aspects are partly linked with the energy saving potential in the cryogenic air separation unit, and partly to emerging sorbents and oxygen transfer membranes (OTM).

On the medium-longer term, chemical-looping combustion (CLC) is expected to have a significant role to play, as CLC opts for almost 100% capture rate without the need of oxygen supply from external processes. In CLC air and fuel are never mixed and the exhaust stream from the fuel reactor will contain mostly CO_2 and H_2O. The energy penalty is thus reduced to being related mainly to the CO_2 compression and purification steps.

In the recent years CLC has been demonstrated at large laboratory scale for both gaseous fuels and coal. However, significant research is still required, mainly in two directions: 1) to develop efficient and versatile reactor systems, and 2) to develop appropriate metal oxides that can withstand the mechanical and chemical stress involved in the cycling between oxidation in the air reactor and reduction in the fuel reactor.

Further development and validation of CLC is highly depending on up-scaling and larger demonstration of reactor systems as well as large scale oxygen carrier production from commercial available raw materials.

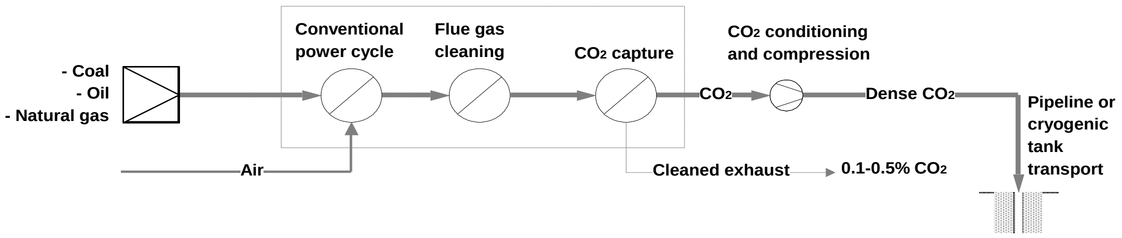
3.3 Post-combustion capture techniques

Post-combustion capture implies that CO_2 is removed from the flue gas after combustion[2]. As the degree of process integration is fairly limited, the concept benefits from the current state of conventional power cycle technology. The main components of the concept are depicted in Figure 7 and its characteristics are summarised in Table 4.

First generation capture techniques integrate the power cycle with an absorption unit, usually based either on amines, amino salts or chilled ammonia. Generally, the degree of integration is limited to steam extraction (typically saturated steam of roughly 4 bar – depending on solvent) and power for pumps, fans and compression.

Second generation techniques will make use of new solvents (absorbers), solid sorbents (e.g. carbonate looping) and even membranes. The latter may affect the power cycle, as membranes usually require a pressure potential. In the case of NGCC the exhaust concentration of CO_2 is low and exhaust gas recirculation is a possible way to increase it. The gas turbines may need modifications, especially in the combustor section, but less than what will be the case for an oxy-combustion gas turbine.

Retrofit of CCS will likely be needed to reduce the global effect of the emissions from power plants in operation and under construction, as pointed out in Chapter 1. The fairly limited process integration needed for post combustion capture makes it the most immediate technology choice for retrofit.



Fuel	Combustion	Oxygen supply	Separation
Coal	Fuel with air (conventional)	no	Absorption (chemical)
Natural gas			Adsorption
			Membranes

Figure 7: Typical post-combustion scheme.

2 As post-combustion technology usually is associated with sorption techniques, the sweetening of natural gas – like the Sleipner project – is prone to be categorised within this group of technologies. In natural gas processing, CO_2 is removed from the gas before the gas is exported and eventually combusted.

Table 4: Brief characteristics of post combustion capture concepts

	Post-combustion
Technology description	Separation of CO_2 from flue gas (after the fuel has been burnt with air) - either via chemical or physical absorption (depending on CO_2 concentration).
CO_2 treatment	Chemical absorption (usually amine-based solutions), or physical adsorption (at higher CO_2 concentration)
Key technology status / availability	Absorption technology known from gas processing and chemical industries, although the power sector units are considerably larger.
Challenges	• Scale and integration of complete systems for flue gas cleaning • Composition of flue-gas (concentration of CO_2, oxygen content) • Slippage of solvent to the surrounding air (possible HSE issue • Energy penalty (steam demand for regenerating the solvent, and power for pumping, compression and – in some cases – cooling) • Water balance (make-up water)
Main features	Comparably low CO_2 concentration (typically 12-15% with coal and 2.5-3.5% with natural gas). Conventional power cycle. Large extraction rate of steam usually at around 4 bar is required for regenerating the solvent.

3.4 Bioenergy with CCS for power generation

Bioenergy with CCS (BECCS) has in the recent years been recognised at an international level as a large scale technology that can in fact achieve net negative CO_2 emissions ([12], [13], [14]). BECCS for power generation can roughly be divided in two categories:

- Biomass co-firing with coal
- Dedicated biomass plants (100% biomass combustion or gasification)

The technical potential for net negative CO_2 emissions of BECCS for power generation is summarized in Table 5 ([13], [14]). The technical potential is the upper limit what can technically be achieved assuming that all global available sustainable biomass[3] is used in one route. I.e. the values in the table cannot be summed and when used in one of the routes, e.g. for co-firing, then there is no biomass left for neither dedicated biomass power plants (nor for biofuels production). The technical potential is mainly limited by the supply of sustainable biomass.

Table 5: Technical potential in global net negative GHG emissions (from [13] which is based on [14]).

	Technical potential in global net negative GHG emissions (Gt CO_2-equivalent)	
Power generation with CCS	**2030**	**2050**
Co-firing in coal power plants (post-, pre-, oxy-combustion)	- 4.3	- 9.9
Dedicated biomass power plants (post-, pre-, oxy-combustion)	- 5.7	- 10.4

[3] 73 and 126 EJ/year in 2030 and 2050, respectively ([14])

The economic potentials are considerable lower, being about one-third of the technical potential in 2050. Using all available biomass in power generation could then yield up to 3.5 Gt CO_2 eq. per year in net negative GHG and power generated from biomass would in that case amount to about 5 PWh (5000 TWh).

Dedicated biomass plants are normally smaller then fossil fuel plants, about 1/10th in general and they are less efficient than fossil fuel plants [12]. Inefficiencies are partly due to the small-scale operation itself, as well as the nature of biomass as a fuel. Biomass is fibrous and inhomogeneous, has lower energy density and contains different inorganic compounds which may cause boiler fouling and corrosion at elevated firing temperatures (necessary for higher efficiency). The smaller scale is also a challenge to the CO_2 transport and storage infrastructure.

Co-firing biomass with coal is a way to increase the efficiency and the scale of biomass conversion. A co-fired plant should in the best case reach about 95% of the efficiency of a coal-fired plant, i.e. about 40% efficiency [12]. With a moderate share of biomass, up to about 10%, the cost of CCS equipment is not believed to be higher than for CCS for coal only [13]. From an engineering point of view a share of biomass as high as up to 50% should be possible to operate in a co-firing plant and several studies in the GCEP workshop [12] supported co-firing as a feasible strategy for bioenergy with CCS.

Both in the case of large-scale dedicated biomass plants and in co-firing plants, some biomass pre-treatment is seen favourable. Thermal treatment such as torrefaction and pyrolysis will reduce moisture, and increase energy density, homogeneity and brittleness. This will reduce costs of biomass transport and storage, and the share of biomass in co-firing can be significantly increased. Pre-treatment does not remove the inorganic compounds of the biomass and problems with boiler fouling and possible corrosion will still be an important aspect to consider for further research and development.

The capture-technologies discussed in Section 3.1 – 3.3 can all be applied in BECCS. However, the composition and impurities of biogenic flue gases and CO_2 streams will generally be somewhat different than from using fossil fuels, e.g. particulates, inorganic compounds and tars. In [13] it is recommended to do further research to evaluate these aspects. Specifically; determine the effect of flue gas and CO_2 stream composition on the power plant value chain (corrosion, effect on solvents, etc.), and identify specific storage issues caused by biogenic impurities in the CO_2 stream.

4 Capturing CO_2 from industrial processes

In the 2DS, CCS from industrial processes is equally important as CCS in power generation with respect to reduction of global CO_2 emissions [1]:

- 2030: about 1.1 Gt/year is captured from industrial processes.
- 2050: about 3.8 Gt/year is captured from industrial processes.

In some regions, especially some non-OECD countries (e.g. India), industrial applications of CCS are far more important than applications in power generation.

Most research and development studies on application of CCS have focused on the power generation sector, clearly reflected in the relatively small amount of literature and independent validation of industrial CCS technologies and costs [15]. This is rather contradictory to the fact that all operational large-scale demonstrations of CCS are in industry and that most of the short-term and cost-effective CCS potential are within industrial processes [16]. Of the eight operational large-scale integrated projects listed by the Global CCS Institute in 2012, six are related to natural gas processing, one to fertiliser production and one to production of synthetic natural gas. In several industry sectors CCS is the only technology that allows for substantial CO_2 emissions reductions since the CO_2 generation is directly related to the core manufacturing process [17].

4.1 Industrial sectors and processes relevant for CCS

The UNIDO report [16] presents five industrial sectors which are significant CO_2 emitters and which offer promising potential for early application of CCS, as well as providing good projections for long-term contribution and sustainable development. The sectors as well as the most relevant processes within each sector are given in Table 6 below together with the most applicable capture technologies.

High-purity sources produce streams of gas with CO_2 concentrations in the range 30 – 100%. These streams offer early opportunities for CCS demonstration projects with relatively low cost compared to other CCS options. Some of these plants will have good access to potential storage sites with known geological characteristics. Capture is today done with existing and mature separation technologies but not optimised for CO_2 transport and storage, and issues such as unwanted co-contaminants in the CO_2 stream should be carefully evaluated. In the case of gas processing the CO_2 removal is a necessity imposed by market or process constraints and the captured CO_2 is just a recycle back to storage. In the longer term the further conversion of the natural gas should also include CCS in order to really contribute to CO_2 reductions from fossil fuel use.

The iron and steel sector is the largest industrial source of CO_2 emissions [1]. Several capture technologies can be used depending on the actual manufacture process. In the shorter term the Top Gas Recycling (TGR) Blast Furnace seems very promising since it can be retrofitted to existing blast furnaces. The ULCOS R&D project and the steel manufacturer ArcelorMittal has proposed a TGR process eliminating nitrogen by injecting oxygen instead of air into the blast furnace. The exiting gas consists of a large share of CO_2 that can be removed by PSA or VPSA plus cryogenics to remove final impurities. The CO_2 is sent for storage whereas the CO and H_2 are recycled back to the blast furnace, acting as reducing agents and thereby reducing the required amount of coke. The planned demo project in France was withdrawn from the European Commission's NER300 scheme late 2012 but the ULCOS R&D project is said to continue as intended.

Table 6: Relevant industrial sectors and production processes for CCS.

Sector	*Production process*	*Capture technology*
High-purity industrial sources	Natural gas processing incl. LNG (onshore/offshore)	Existing industrial gas separation technologies.
	Coal-to-liquids (CtL)	
	Ethylene oxide production	
	Ammonia production	
Iron and steel	Blast furnace	Top gas recycling + PSA[4], VPSA[5] or chemical absorption. Oxyfuel blast furnace.
	Direct reduction of iron (DRI)	Pre-combustion (reforming/gasification) + PSA, VPSA or chemical absorption.
	FINEX technologies	PSA
	The HIsarna process	PSA or VPSA
Cement	Kiln / calcination	Post combustion with chemical absorption. Oxyfuel technology. Calcium looping.
Refineries	Hydrogen production by natural gas steam methane reforming	Chemical absorption. PSA.
	Hydrogen production by residues gasification	Pre-combustion (gasification) + physical absorption
	Fluidised catalytic cracking	Post-combustion absorption. Oxyfuel technology.
	Process heat	Post-combustion separation. Oxyfuel technologies
Biomass conversion	Synthetic natural gas	Pre-combustion (gasification) + absorption.
	Ethanol production	Relatively pure CO_2 stream, only dehydration needed.
	Hydrogen production from biomass	Pre-combustion (gasification) + absorption.
	Black liquor processing in pulp and paper manufacturing	Pre-combustion (gasification) + absorption.

[4] Pressure Swing Adsorption

[5] Vacuum Pressure Swing Adsorption

Cement industry can make use of the same post-combustion capture technologies as used in the power sector. They can be retrofitted to existing plants at low technical risk. One drawback in cement industry is the limited availability of low-grade heat for regeneration of the chemical solvent. Oxyfuel has been shown to be a more cost-effective option [15] but is generally more suitable for new plants. The effect of the higher CO_2 concentration in the calciner and in the rotary kiln is one challenge being investigated. A third option is the calcium looping cycle. This has a natural fit since the waste products from the CO_2 capture can be recycled as raw materials for the cement production. One important research area is the possible build-up of trace elements since CaO fed to the kiln has already been circulated in a carbonation/calcination cycle, and how they may affect cement quality. No significant effect has been found so far [15]. This technology deserves increased focus since it offers very good process match and low avoidance costs and efficiency losses according to UNIDO [16].

Within refineries several CO_2 capture options exist. One recent achievement is oxyfuel technology applied to a fluidised catalytic cracker (FCC). The FCC unit is responsible for some 20 – 30% of total CO_2 emissions from a typical refinery. During 2012 the CO_2 Capture Project has performed a field demonstration of oxy-firing in a FCC unit at a Petrobras research complex in Brazil [18]. Key results are: Fast and smooth switch between air and oxy-firing; Possible increase in production rate would help mitigate the cost of CO_2 capture; Efficient and stable operation confirmed oxy-firing as viable and economically competitive with post-combustion technology.

The potential of CO_2 capture from biomass conversion is expected to increase significantly following the expected increase in global biofuels production [17]. Capture from biomass conversion may achieve net negative CO_2 emissions, depending on the proper biomass production. Biomass conversion for fuels can be done in two ways:

- Bio-chemical production (fermentation). E.g. bioethanol.
- Thermo-chemical production (gasification). E.g. Fischer-Tropsch (FT) biodiesel.

Fermentation produces a relatively pure CO_2 stream which only needs drying. The other biomass conversion processes in Table 6 are based on gasification and CO_2 can be removed by pre-combustion separation techniques such as absorption, adsorption or membranes. Removal of tars is an additional challenge related to biomass conversion.

The technical potential for net negative CO_2 emissions is smaller for biofuel plants with CCS than for biomass power generation with CCS [14] since some of the carbon has to leave the process with the biofuel product. On the other hand, what is available for capture is in the form of rather pure CO_2 streams which makes separation easier and less costly. For FT biodiesel processes as much as about 50% of all the carbon fed to the process is released as relatively pure CO_2 [13] and the technical potential for net negative CO_2 emissions can be up to about half of the values estimated for biomass power generation shown in Table 5. More interestingly, since the difference between the technical and economic potential for the FT biodiesel process is less than for the biomass power generation processes (because of the pure CO_2 stream and less costly separation), the economic potential of this process is almost at the same level as the biomass power generation processes [14].

4.2 Oxygen production for CO_2 capture in industry

As shown in the table, several of the CO_2 capture technologies among all the highlighted industrial sectors will need oxygen. Oxygen is also needed in power generation CO_2 capture in the oxyfuel route as well as in many pre-combustion processes. Thus, further research and development within oxygen production to reduce cost and energy consumption will have a high potential if significant improvements are made.

5 CO_2 transport

According to the Global CCS Institute [2], the aggregated length of pipelines covered (or to be covered) by 75 large-scale integrated projects currently under development and in operation is around 9000 km. More than 70 per cent of these projects are looking to use onshore pipelines, in particular in the US and Canada. This planned infrastructure development is approximately 1.5 times the size of the existing network of dedicated CO_2 EOR pipelines presently available in the US.

So far, North America has 36 CO_2 pipelines – with a total length of 6500 km – dedicated to enhanced oil recovery (EOR). Each year, some 48–58 Mt of CO_2 is piped basically in a dual-node system (i.e. single source to single sink). The aggregated amount of CO_2 handled by these pipelines corresponds roughly to the quantity of CO_2 emitted from the largest power plants, such as the Taichung power station in Taiwan (cf. Figure 8).

Offshore pipelines are mainly considered by projects in Europe, in particular in the Netherlands, Norway, and the UK. In these countries projects are looking to transport their CO_2 via pipeline or ship to various offshore storage locations in the North Sea. The only offshore pipeline for CO_2 currently in use is part of the Snøhvit project (Norway), which has been operational since 2008 and covers some 153 km linking Hammerfest to the Snøhvit field under the Barents Sea. Further CO_2 transportation by pipeline in Europe occurs in the Netherlands, with approximately 85 km of pipeline supplying 300 kt per annum of gaseous CO_2 to greenhouses, as well as other pipelines in Hungary, Croatia, and Turkey for EOR [2].

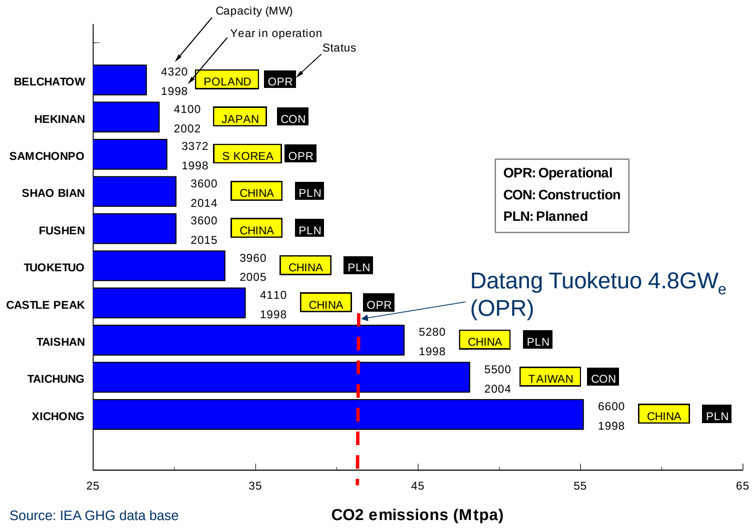


Figure 8: Single-point emissions from the world's largest coal power plants.

In the future, in order for CCS to be swiftly deployed on a large scale, new transport systems are required to handle the vast volumes of CO_2 to be captured in future power plants and industrial clusters. This calls for a new infrastructure along with systems for the handling of CO_2 from multiple sources to multiple sinks. As the number of sources grows within the power sector and industries and more storage sites are envisaged, a system of discrete nodes and connectors must be drawn. In this context, logistics planning and infrastructure development appear as a cross-cutting issue linking technical aspects, purity and composition of the various CO_2 streams, storage capacities, geographic constraints, societal issues and public engagement. This work has already been initiated, e.g. in the European project CO2Europipe. Studies are also made around hubs and clusters for CO_2 in the UK, Australia, United States and in the Dutch ROAD project, as well as in the United Arab Emirates and Alberta, Canada [2].

Specific concerns and challenges are raised, as to the need for efficient and safe handling of the CO_2. Firm actions are required to close specific knowledge gaps related to transport and storage of CO_2-rich mixtures from differing CO_2 sources, to enable the realisation of safe and cost-efficient solutions for CCS. In this context, it remains to develop a knowledge base as required for defining industrial norms and regulations ensuring safe and reliable design, construction and operation of CO_2 pipelines. These needs can only be addressed through fundamental research on thermal, physical and chemical properties merged with metallurgical integrity and behavioural impacts of mixtures made up predominantly by CO_2.

Whereas pipelines, laid, eventually, over land and seabed are believed to predominate over tanked CO_2 in a fully developed infrastructure, transport by ship, rail and road is expected to have an impact especially in the initial phase of CCS and CCUS deployment. As pipelines must handle CO_2 at supercritical pressure and ambient temperature in dense phase, tanked CO_2 is usually cooled to liquid state (i.e. close to the triple point, either at atmospheric or meso pressure, typically 6-10 bar). Devices for loading and unloading of tanked CO_2 to meet the requirements of the system are needed, especially for offshore operations. Furthermore, as the specific volume of dense and liquid CO_2 is rather low, the flow characteristics of liquid CO_2 allow for the transport of large quantities of CO_2 through pipes with fairly small diameters. For instance, in the 160 km subsea transport system of the Snøhvit project, 0.7 Mtpa of CO_2 is transported in a pipeline with only 200 mm diameter (8 inch).

Furthermore, as will be explained in more detail in section 8.1, the timeline for CCS should be no longer than one decade in order for CCS to comply with the 2DS. This calls for unprecedented actions, as the required systems for handling the vast volumes of CO_2 must be developed and become operational at the same pace as commercial capture facilities start to operate and the required storage capacities are made available. This requires an exponential growth rate corresponding to three orders of magnitude per decade. So far, no approach is known as to how to turn top-down strategies of this extent into practical (bottom-up) actions.

6 CO_2 storage

Nearly 123 gigatonnes of carbon dioxide ($GtCO_2$) need to be safely stored in geologic formations by 2050. A vast majority of this storage volume is likely to be in deep saline formations. In the 2 degree scenario the total global storage rate is 2.41 $GtCO_2$ per year in 2030, growing to 7.83 $GtCO_2$ per year in 2050. Currently, 23.2 $MtCO_2$/year is stored in operating large scale integrated CO_2 storage projects [2]. Of this 2.7 $MtCO_2$/year is stored in deep saline formations, the rest is used for EOR [1].

Options for geological CO_2 storage

- Deep saline formations (DSF): Wide spread and vast potential
- Depleted oil and gas fields (DOGF): Explored, penetrated by wells, potential for reuse of equipment and infrastructure, limited capacity, potential for EOR/EGR. Combination with aquifers.
- Other options: Un-mineable coal beds, basalts, oil shale, ..

The technologies and operational aspects of CO_2 injection and storage are demonstrated in existing CO_2-EOR and acid gas disposal operations.

Challenges

According to the ZEP survey of EU demonstration [19] the greatest concerns relate to the identification, qualification and validation of storage sites – 50 % view this as a serious challenge or key blocker. 30 % also recognise that some aspects of storage technology can only be addressed in the operation of the demonstration project itself, whereas 90 % have no major concerns regarding capture technology.

- A massive increase in number of large scale CCS projects is needed
- Each geological storage site is unique and must be extensively explored
- CO_2 storage represents a long-term financial liability
- CO_2 storage represents a major public perception challenge.

6.1 Regional assessment of storage potentials

Methodologies for storage capacity estimation can be broadly divided into static and dynamic methods. Static methods consider the equilibrium state after CO_2 injection (mainly based on the compressibility of CO_2 and water) and typically involve the use of an efficiency factor (S_{eff}) multiplying the available pore space. Dynamic methods also consider the transient pressure development and injectivity, thus being better able to take into account the restrictions pore pressure increase (local and regional) places on the utilization of a storage formation. Dynamic methods, using detailed flow models, are typically used in capacity estimation for specific storage sites that have been already selected, and in generic studies to determine good choices for S_{eff}. Static methods are typically used in initial screening phases for regional storage potential and identification of potential storage sites, but the accuracy of capacity estimates in turn depends on a good estimate of the storage efficiency factor. At present there is no common agreement on how S_{eff} is best calculated, but the disagreement can mostly be assigned to the choice of open vs. closed boundaries, and whether extraction of pore fluids (brine in DSF) should be accounted for [20]. As long as the assumptions used are openly stated, recalculations of storage capacity should be straightforward for a new choice of S_{eff}.

Methodologies applied in regional CO_2 storage assessments are similar at their core, but there has been a difference in the constraints placed on what constitutes a storage resource and therefore should be included in the capacity estimate. A range of local policy constraints have been applied, making the comparison of technically accessible potential difficult. Two workshops were organized by IEA in 2011 to recommend guidelines for a common methodology for arriving at jurisdictional or national-scale geologic CO_2 storage resource assessment [21].

An important uncertainty in storage capacity estimation, especially in saline formations, stems from the lack of exploration data. While DSF have higher potential capacities than DOGF, there is greater uncertainty in capacity estimation due to more limited characterisation data and understanding of long-term trapping mechanisms. This highlights the need for exploration data acquisition for large DSF, as these not only represent the largest volume of available storage, but could also show considerable scope for economies of scale due to their size [22].

Reliable and robust predictions of storage capacity are fundamental to the efficient and safe demonstration, and ultimately the longer-term deployment, of CCS technologies. Identification of potential storage sites, with risk-based estimates of storage capacity, allow policy-makers to determine the extent to which CCS might contribute to reductions in CO_2 emissions at national and regional levels, as well as the timing of, and route to, achieving initial demonstration and subsequent wider deployment to maximize optimal use of the storage resource. Individual storage sites require accurate estimates of storage capacity to provide robust assessments of both the technical and financial business case for the site.

Several regional storage capacity estimations have been conducted:
- Carbon Sequestration Atlas of the United States and Canada I, II, III and IV
- The North American Carbon Storage Atlas 2012
- The CO_2 Storage Atlas Norwegian North Sea 2011
- Queensland carbon dioxide geological storage atlas.
- South Africa CO_2 Storage Atlas
- Storage Catalogue of Germany (GIS)
- UK Storage Appraisal Project (UK SAP) (GIS)
- The Brazilian Carbon Geological Sequestration Map (CARBMAP Project)
- The geo-database of caprock quality and deep saline formations distribution for geological storage of CO_2 in Italy (GIS)

These regional assessments not always identify to a sufficient degree the potential resource conflicts.

6.2 Methods for screening and exploration of sites with storage potential

Methods for screening and exploration of storage potential have been developed, based on the long experience with petroleum exploration and production, natural gas storage, and the management of ground water resources. The choice of method for a particular site/region must be suitable for the particular geology found there. Due to the geological variability and also the general scarcity of pre-existing data, probabilistic methods should be employed in the storage potential assessment. A challenge for deployment in the 2020-timeframe is the required time for data collection and analysis (but also for licensing and other regulatory procedures), in particular for SA in regions not explored previously ([2], [23]).

The Ministry of Petroleum and Energy (NPD), Norway, will call during 2013 for an Exploration license round, based on nominated CO_2 Storage sites and the Storage Atlas by NPD. Prior to any financial investment decision for projects to take place in 2018–2020, the proposed sites in the North Sea will require exploration/appraisal drilling in 2013–2018.

The EU7FP SiteChar project [24] notes that: “Storage exploration requires the development of a credible scenario of CO_2 storage injection over a 25–50 years term, compatible with likely current and future industrial sources”. A full-chain techno-economic assessment is needed to reach readiness for storage license application. The SiteChar project is developing a site characterization procedure for a multi-storage complex with structural traps and open saline formations. For example, the procedure needs to be risk-based and focus first on the high-risk aspects.

SiteChar is exploring the possibility to use basin modeling tools to give a first estimate of dynamic storage capacity without having to perform full reservoir simulations. Challenges for this method are lack of data in areas where the oil industry is not present. For many regions across the globe this is being addressed by public programs to provide geologic data (e.g. in the US, Australia, UK, Canada).

CO_2-EOR is widely practiced throughout the onshore Permian Basin in the US, though optimizing for CO_2 storage is not a priority in these operations. Nevertheless, some of the CO_2 injected in these operations is stored, and therefore, much can be gained from the North American EOR experience. CO_2-EOR projects linked to CCS are now beginning to be proposed for the North Sea and may provide some opportunities to evaluate optimized strategies for increased oil production and CO_2 storage.

6.3 Advanced simulation tools for fundamental processes

The primary technical issues associated with storage are the difficulty of quantifying actual storage capacity; the movement of the injected CO_2 and long-term security; verifiability; and the environmental impact of storage. The need to use models to address these issues is recognized as essential and existing regulations, such as the EC Directive 2009/31/EC on the geological storage of CO_2, and the EPA Class VI Injection Well Rule, describes modelling requirements.

Modelling tools are being actively developed, and for many physical processes relevant for geological storage of CO_2 acceptable tools already exist. To increase the reliability of predictions of long-term security there is still a need for development. The break-out session on Simulations and Risk Analysis at the NETL workshop on carbon storage R&D needs [25] highlighted the need for: improved simulation codes for geomechanical process in general and, specifically, induced seismicity; description and modelling of geologic heterogeneity, including compartmentalisation and fractures; description and modelling of leakage processes, including fault flow. The workshop also pointed to the lack of input data to constrain the models being developed, in particular for complex, coupled long-term systems.

Development of coupled models for multi-phase flow, thermodynamics, geochemistry and geomechanics is ongoing, as is apparent from the list of presentations at recent conferences such as the GHGT-11 International Conference held in Kyoto in November 2012.

In general, ongoing storage projects (such as Weyburn, Sleipner, and several others) provide good examples of the implementation of safe geological CO_2 storage under a wide range of geological settings. The range of geological settings needs to be expanded to provide data and samples to be able to further improve confidence in modelling and monitoring tools.

Models making predictions for long-term security need to cover such elements as various trapping processes, alterations in cap-rock integrity due to exposure to CO_2, and plume migration over large distances. There is still a lack of benchmarking data for calibration of such models. This can be expected given the state of development of large-scale geological CO_2 storage. Research is ongoing to develop improved understanding and modelling capabilities for necessary processes, such as up-scaling of trapping mechanisms in a heterogeneous geology, modelling of thin-layer CO_2 migration, changes in wettability conditions due to CO_2 exposure.

Because of the complexity of the models and the large areas that needs to be studied for CO_2 storage operations a fundamental issue is computing power. The computing time using parallel processing and supercomputers is allowing geological complexity to be dealt with, but uptake is slower in the geosciences.

6.4 Methods and tools for securing and monitoring injection and long-term containment

Site selection

Among the potential CO_2 storage site types under discussion such as depleted oil and gas fields (DOG), deep saline aquifers (DSA), and coal beds, DSAs provide the largest storage capacity. Active oil and gas production sites offer an economic opportunity to store CO_2 by means of enhanced oil recovery (EOR), but the storage capacity is believed to be much smaller than in DSAs. Potential sites have to be evaluated in terms of storage capacity and safe storage of CO_2, i.e. evaluation of the reservoir properties including depth, pressure, porosity, permeability, salinity, and evaluation of the caprock properties including lateral continuity, thickness and capillary entry pressure [26]. The Carbon Sequestration Leadership Forum (CSLF), the US Department of Energy (DOE) Regional Carbon Sequestration Partnerships, and CO2CRC have proposed methodologies to assess CO_2 storage capacity of potential sites. SiteChar is currently (2011–2013) answering to the need for

- an improvement and a harmonization of methodologies for estimating the potential and capacity for CO_2 storage capacity in geological media,
- an application of the methodologies along the full workflow from country-scale to site-scale and in particular from theoretical to matched capacity,
- a better understanding of (i) the physical and chemical processes and (ii) the engineering and economic aspects that reduce the storage capacity from the theoretical estimation to the effective and to the practical ones,
- a portfolio of representative case-studies for CO_2 storage capacity estimation at various scales and in different geological settings.

The challenge of site selection lies in the difficulty to make reliable site ranking and selection without drilling new, exploratory wells and acquiring new seismic and other geophysical surveys. Additional characterization activities to reduce uncertainty can make the initial site characterization expensive with a high risk of negative or insufficient results.

Monitoring programmes

Large scale projects on-shore and off-shore (e.g. Otway, Sleipner, InSalah, Snøhvit, Weyburn, K12-B, Ketzin) have demonstrated that monitoring technologies are already available to monitor stored CO_2. Key techniques are time-lapse seismic and down-hole pressure and temperature monitoring for deep monitoring, tracking the plume and leakage detection [27]. Additional methods are time-lapse gravimetry, seabed bathymetry and controlled source electromagnetic at Sleipner; passive seismic, electrical resistivity imaging, geochemical and soil-gas surveys at Weyburn; microseimic, InSAR, groundwater monitoring, soil-gas and microbiological surveys, complex wireline logging at In Salah; extensive logging at K12-B; VSP, MSP, passive seismic, geoelectrical monitoring, microbiological and geochemical monitoring at Ketzin. One major conclusion from all these monitoring projects is that there is no "one-size-fits-all" monitoring program (see also the IEA GHG Monitoring Selection Tool http://ieaghg.org/co2tool_v2.2.2_product_joomla/index.php#). Technologies for monitoring stored CO_2 at one site may not work at all for others. But suitable combinations of other tools might provide the required information (In Salah: the cost-effective method of satellite measurements coupled and inverted with geomechanical models was successful in assessing the spatial extent of the subsurface pressure front).

Uncertainty and risk assessment

The verification activities in the CO2ReMoVe project [28] show that monitored site performance almost always deviates from initial predictions. Despite of the deviation, CO_2 has been stored safely and effectively. This deviation is due to a number of inherent uncertainties:

- unknown full geological complexity
- the dynamic model cannot capture the full resolution of the (imperfectly understood) static model
- complex fluid flow properties are not fully understood
- monitoring tools have limited resolution and inversions of the monitoring data can be non-unique.

For each site, acceptable deviations need to be established, and the convergence of predicted and observed site performance with time has to be demonstrated as a site-specific monitoring strategy ([27], [29]).

Quantitative risk assessment will depend on the extent of which types of uncertainty are addressed in calculations. One example is the work presented in [30] on an integrated workflow to describe quantitative risk assessment within CCS. Starting with a qualitative analysis and scenario definition potential risky scenarios are defined. These are subsequently investigated in a quantitative way (fast models or fully developed numerical codes). The scenario analysis includes modeling of the reservoir and caprock behavior, well integrity evaluation and migration path analysis. Sensitivity analysis is addressed by probabilistic means. Finally, the consequences of potential surface leakage are addressed, resulting in a clear picture of the risks at a specific site / time. The presented methodology will be tested on a real offshore gas field.

Ensuring storage integrity

While a proper CO_2 storage site is not expected to leak, there is a need to be prepared for the event of leakage in terms of detection and remediation.

One of the biggest risks for CO_2 leakage is presented by well barrier loss through accessible wells, plugged and abandoned wells, spread of the CO_2 to an unintended storage complex formation (thief zone) through the wellbore and unknown wells. There are ~65,000 wells in the North Sea, ~500,000 wells in western Canada and 1,000,000 wells in Texas alone. The experience of the oil and gas (O&G) industry is highly valuable for CO_2 storage wells because e.g. aging issues with cement degradation, casing corrosion and thermal loads imposed to the well infrastructure are of similar concern in both applications. Thus, many different monitoring techniques of the O&G industry are available for CO_2 leakage both within the wellbore and at the surface, around the wellhead ([31], [32]). With abandoned wells, the applicable monitoring methods are basically limited to surface measurements (CO_2 or tracer concentration, ecosystem stress monitoring, groundwater monitoring), unless these wells are re-entered and the mechanical plugs and cement plugs are drilled to provide access to the wellbore (wireline logging). Thus, knowledge of the locations of abandoned wells is highly valuable to concentrate surface monitoring layouts on those locations. In case of leakage, the O&G industry provides a wide range of technologies and methods to mitigate and remediate well leakage. Several types of emerging or novel technologies and materials have been suggested, but not been tested yet.

The second most likely leakage scenario is presented by a natural barrier breach leading to migration of CO_2 or displaced brine through a breach in the seals via faults and fractures. The determination of the exact location, geometry and sealing capacity of faults belongs to the most important and most difficult goals of site characterization. A first-order characterization (sealing nature) can be obtained from 3D seismic and borehole data, particularly rock properties and breakout data. Accurate mapping of fault networks, especially small localized areas of intense faulting, e.g., on structural crests, requires high quality 3D seismic data. Identification of fracture networks is much more difficult and requires cored sections and borehole image logs (very local information). Pressure measurements only assess the large-scale heterogeneity (compartmentalization, sealing nature) of the storage container ([33], [29]). Monitoring layouts (e.g. 4D seismic, well-logging, surface deformation) will be concentrated on areas above or close to (known) existing faults to allow an early detection of a potential leakage, and of (induced) changes in fault extent, shape and properties (time-lapse measurements).

Other leakage scenarios can be described as loss of conformance in the reservoir due to reservoir compartmentalisation (leading to unexpected increase of injection well pressure), spread of the CO_2 plume beyond the desired region (e.g. spread beyond the spill point in a structural or stratigraphic trap; or migration beyond the predicted/modeled limits in an open aquifer). Reliable continuous reservoir pressure measurement (O&G industry) allows to timely detect a change in the reservoir behavior, e.g. due to a sudden or slow change in fault integrity. Monitoring methods for potential leakages of CO_2 from the reservoir are the same as for monitoring of the reservoir: 4D seismic and well-logging in monitoring wells or surface deformation monitoring. Results from those surveys should lead to updates in both reservoir and geomechanical models and simulations, including the characteristics and role of the fault system. In case of CO_2 leaking up to the shallow subsurface and surface, a number of additional monitoring methods are specifically useful for shallow detection: induced polarization, spontaneous potential, vegetation stress and changes, color infrared transparency film, thermal hyperspectral imaging, biological monitoring, soil and atmospheric gas sampling, water sampling. So far, only few field laboratory experiments have been performed to test the different monitoring and modelling techniques on leakage through faults ([34], [35]) and through seepage ([36], [37], [38]).

A challenge lies in the determination of detection limits of the more indirect methods like seismic: Not only do they depend on the tools and acquisition geometry but also largely on the geological setting, and have thus to be determined case by case, if possible at all. Furthermore, while leakage is likely to be detected, quantification of leakage through a fault of spill point still remains a challenge: While seismic waves are very susceptible to the presence of CO_2, it is impossible to quantify the mass of underground CO_2 because resolution limits prevent both an accurate volumetric and saturation estimation. The ongoing project CO2FieldLab [39] aims at determining detection limits of monitoring methods in the near-surface and surface, however, even in the shallow subsurface the challenge remains that detection limits depend largely on the geological setting. While the surface detection and direct measurements can provide very accurate measurements, the challenge here lies in the ideal positioning of the equipment to monitor surface leakage rates.

Suggested mitigation and remediation actions in case of unwanted CO_2 migration are mostly based on flow diversion by operation migration management, e.g.:

- Localized reduction in permeability by e.g. the injection of gels or foams or by immobilizing the CO_2 in solid reaction products
- Change of injection strategy
- Localized injection or production of brine creating a competitive fluid movement and/or changes in pressure.
- A targeted pressure management achieved by either brine withdrawal (preferable outside the actual CO_2 plume) or
- CO_2 back-production from inside the CO_2 plume
- Injection into an alternative formation: One of the few cases of unexpected events requiring intervention was the undesired pressure build-up at Snøhvit, which was threatening the cap rock integrity. It was remediated by perforating the injection well in a shallower formation ([40], [41]).

A number of projects have investigated remediation actions in the near surface by

- studying natural analogue settings (Laacher See Germany; Latera, Italy)
- setting up and studying experimental sites (ASGARD, Nottingham; ZERT site in Montana, RISCS project experimental site in the UK)
- studying industrial analogues (numerous CO_2 EOR projects especially in North America).
- GFZ with partners has long proposed to model and test a few of the flow diversion procedures on their Ketzin site, but has not started yet.

In their 2013 call, the European Commission is responding to the need of mitigation and remediation procedures in case of CO_2 leakage for different scenarios, for example well integrity, impaired caprock (dissolution, faults/fractures), spill point outflow, secondary CO_2 accumulations in shallow aquifers or soils, and eventually surface release. Research should include a thorough analysis of the mechanisms controlling the migration of CO_2 out of the storage target. Results from the project - mitigation and remediation methodologies - shall be published as guidelines which can feed into the regulatory process for storage permitting, in particular into the corrective measures plan for storage site operators pursuant to the Directive on geological storage.

Regulations and protocols, documentation of containment

The European parliament has issued two directives in 2008:

- The Carbon Capture and Storage Directive: implementation and safety of storage sites. It mentions that the "monitoring plan should enable the detection of significant irregularities, migration and leakage outside the storage complex."

- The European Trading Scheme Directive: includes CCS. Therefore, a standardized set of monitoring protocols will need to be defined to monetize carbon credits. This includes the capacity to detect and quantify leakage.

In December 2010, the United States Environmental Protection Agency (EPA) finalized requirements for geologic sequestration under the authority of the Safe Drinking Water Act's Underground Injection (UIC) Program. The rule addresses requirements for long-term storage of CO_2 to ensure that wells used for geologic sequestration are appropriately constructed, tested, monitored, funded, and closed. Regulations for EOR previously existed.

The EPA also issued a complimentary rulemaking under the authority of the Clean Air Act which details reporting requirements under the Greenhouse Gas Reporting Program for facilities that inject CO_2 underground for geologic sequestration and all other facilities that inject CO_2 underground. Information obtained under this program will enable EPA to track the amount of CO_2 received by these facilities.

In Alberta, Canada, where injection in the subsurface falls under provincial jurisdiction, legislation has been passed, under which the Alberta government owns subsurface pore spaces where carbon dioxide is stored and assumes long-term liability for injected carbon dioxide once project operators provide data that the gas is contained. Under this bill, a special fund financed by CCS operators pays for future monitoring of underground carbon dioxide storage sites and any necessary remediation.

Even though Monitoring, Verification and Accounting (MVA) are explicitly required in all directives, protocols to perform such tasks are not yet mature. The CO2FieldLab project aims to propose a methodology for designing a MVA plan and a protocol to certify it. However, as stated earlier, a "one-size-fits-all" monitoring program is unrealistic.

Knowledge sharing

Knowledge sharing is a key requirement and activity of the Global CCS Institute (GCCSI) and the Carbon Sequestration Leadership Forum (CSLF). The CO2GeoNet network and the CGS Europe project are networks with the objective to build a credible, independent scientific body of expertise on CO_2 geological storage, with the ambition to promote and enable research integration within the scientific community to help enable the implementation of CO_2 geological storage. Much of the information presented here is taken from the knowledge repository reports of CGS Europe.

6.5 Guidelines and best-practices

Knowledge transfer from research and learning through sharing of experience from CO_2 storage projects is a key enabler to successful implementation of large scale CO_2 storage at the pace needed to meet the targets set by the IEA 2DS. In this, development of standards and best practice guidelines are important instruments to accelerate information exchange and technology development. Moreover, it is pointed out by the Global CCS Institute [2] that the coordination of technical needs and fostering the transfer of findings among research and industrial communities is important for the broader CCS community. Over the last few years, many publications were released covering the best practices, guidelines and standards for CO_2 storage.

CO2CRC [42] summaries manuals and guidelines for CO_2 storage and the presentation are supplemented by a table illustrating the topics covered and the level of coverage provided.

The CSLF Task Force on "Monitoring of Geologic Storage for Commercial Projects" has been recently set up and has decided to identify and review existing standards, guidelines and best practices on an annual basis. Initially, the work focuses on identifying current standards and guidelines to provide a basis for later assessment of shortcomings and proposals for improvements. In addition to the standards identified by CO2CRC, the CSLF Task Force will identify standards and guidelines released after the CO2CRC report (e.g., NETL WM Best Practices for Carbon Storage Systems and Well Management Activities [43], NETL Risk Analysis and Simulation of Geological Storage of CO_2 [44], Det Norske Veritas (DNV) CO_2 Wells [45], and Canadian Standards Association (CSA) Z741-Geological storage of CO_2 [46]).

In 2011 ISO convened the Technical Committee 265 [47] to examine CO_2 capture, transport and storage and the scope of the committee is expected to include standards related to the whole CO_2 chain.

6.6 Cost of CO_2 storage

The European Zero Emission Platform (ZEP) report "The Costs of CO_2 Storage - Post-demonstration CCS in the EU" [22] presents cost estimates based on ZEP members' extensive knowledge and experience. The report states that location and type of field, reservoir capacity and quality are the main determinants for costs. Not surprisingly, onshore storage is found to be cheaper than offshore storage. Storage in larger reservoirs is cheaper than storage in smaller ones and sites with high injectivity are cheaper than sites with poor injectivity. Due to available knowledge and re-usable infrastructure DOGF are cheaper than deep DSF. The costs vary from €1–7 [USD 1.3–9]/tonne CO_2 stored for onshore DOGF to € 6–20 [USD 8–26]/tonne for offshore DSF. Large, onshore DOGF are the cheapest storage reservoirs, but are also the least available. The high costs related to DSF confirm the substantial need for reservoir screening and exploration compared to DOGF where extensive information is already available. It also reflects the risk of spending money on exploring aquifers that are ultimately not suitable for CO_2 storage. The ZEP report pinpoints the need for some risk-reward mechanisms to stimulate early phase investments in SA exploration to map the storage potential.

The total storage costs vary up to a factor of 10 for a given case. Even though the well costs are about 40–70% of total costs, it is the (geo) physical variations more than the uncertainty of cost estimates that drives the wide cost ranges. Consequently, there is a need to develop exploration methods that can increase the probability of success and/or lower the costs of selecting suitable storage sites. CCS demonstration is identified as an essential measure, since more operational storage facilities will contribute to verifying storage performance.

The UK Carbon Capture and Storage Cost Reduction Task Force were established in March 2012 to advise government and industry on the potential for reducing the costs for CCS. Among the main sources of potential cost reduction identified by the Task Force are investment in large CO_2 storage clusters supplying multiple CO_2 sites, reduction in costs through measures to reduce risk and improve investor confidence in CCS projects and exploitation of synergies with CO_2 based EOR [48].

6.7 Securing safe and timely CO_2 storage

Basic data for storage qualification, injection and containment

Although ongoing demonstration projects have supplied a wealth of legacy and new data for the development of geological CO_2 storage, access to data remains a critical knowledge gap to advance storage projects and the underpinning technology to a sufficiently mature state for large-scale deployment. The (natural) focus for exploration for O&G has been the oil and gas reservoirs, and this means that there is a particular lack of data for assessment of cap-rock properties and how these may be affected by exposure to CO_2 and to the changing mechanical and thermal stress conditions as CO_2 is injected. For saline formations outside of the main O&G provinces the lack of data may be even worse. The necessary exploration efforts and time to properly characterise potential storage formations are often underestimated, leading to bottlenecks for timely deployment of CCS.

CO_2 storage has special needs with respect to exploration and appraisal drilling, notably in characterization of non-petroleum-play basins, in understanding regional formations pressures and in confirming sealing capabilities of the sealing formations. Therefore, there is a challenge in improving the understanding of the geology and conditions in storage prospects and of the techniques and analysis for characterisation of CO_2 storage prospects, which differ from those used for hydrocarbons. An improved understanding of the overburden, which is essential in the evaluation of CO_2 leakage scenarios and secondary barriers, hence will contribute to the certification of sites for CGS.

For offshore areas, access to suitable drilling rigs and ships is challenging and may be in conflict with other drilling programmes.

There is also a need to confirm the stratigraphy and character in seal and storage strata, which may span international boundaries, in under-explored parts of basins. Scientific research and exploration drilling, focussed on collection of new data from potential storage complexes (aquifers and caprocks) will bring new insights into the geological capacity and containment potential, and help accelerate the commercial development of CCS.

Procedures for CO_2 storage drilling must also mature in order to define optimal data acquisition plans and to reduce costs. The need for appraisal drilling and data acquisition has been pointed out by the Zero Emission Platform, among their R&D recommendations.

A thorough assessment of reservoir and caprock integrity is required for any potential sub-surface CO_2 storage site. Risks to be assessed include stress, pore-pressure, chemically and thermally induced rock failure and fault reactivation. For such an assessment, the initial subsurface stresses as well as rock-mechanical properties need to be known.

An improved availability of (well-preserved) samples from potential sealing formations, will allow studies of the impact of CO_2 on rock-mechanical properties, which is still not sufficiently understood. The interaction of fluid saturated rocks with CO_2 is highly complex as CO_2 changes the pH of the pore fluid, which may result in mineral dissolution and/or precipitation, as well as strength and stiffness changes. To date, the industry lacks best practices for assessing the impact of CO_2 on reservoir and caprocks and its impact on caprock integrity.

Challenges related to collecting enough data and knowledge before operations starts:

- Access to data remains a critical knowledge gap to advance storage projects and underpinning technology (e.g. geology, hydrogeology, geomechanics, geochemistry, thermodynamic data)
- Site scale and site specific data in particular for saline formations. Locate viable sites and understand the reservoir. Important to include in plans to avoid delays and operational challenges and to be able to optimise injection and storage capacity.
- Efforts for site exploration include several major cost elements (e.g. seismic programs, appraisal drilling. Critical to prioritise because the results represent the basis for multi-million investment decisions. Cost must be seen in context of the total costs of the CCS chain where CO_2 capture dominates.
- Baseline data acquisition – detailed site characterisation and monitoring prior to, during, and after injection. Several methods applied to tests to define volume, injectivity, integrity of the cap rock, description of faults/fractures and leakage paths, integrity of wells (Linked to the previous section?) Background information (e.g.CO_2 concentrations prior to injection, seismic activity)
- Operational data needed to improve knowledge, models and technology and to increase public understanding and confidence.

Lead time

The Global CCS Institute project survey in 2011 points out that storage characterisation, which is site dependent, may represent a main risk for delay in large scale CCS projects. Storage assessment should be at least as advanced or even more advanced as the other components in the CCS chain. This is particularly important when aquifer storage is planned because the sites have not been investigated as part of the oil/gas production. The same project survey indicates a lead time of 5-10 years or more for green field storage assessment. National programmes to screen potential storage sites (e.g. Australia, USA, Brazil, Europe, China) is one factor that may contribute to reducing the lead time.

The IEAGHG study [23] indicates that it can take 4–12 years to reach bankable status when evaluating deep saline reservoirs or depleted oil and gas fields. Projects based on CO_2 EOR are more geographically restricted and may be bankable within 1–3 years. The survey confirms that much of the effort is focused on data acquisition and technical evaluation of a proposed site, but the time related to licensing and addressing environmental regulations is also significant. In addition, the gap from achieving bankable status to commencement of operations (encompassing construction and commissioning) can be more than three years. Consequently, storage sites must reach bankable status around 2015–17 to be operational by 2020 and it is a significant challenge to reach the ambitions envisaged by G8 leaders in 2008 of having CCS broadly deployed by 2020.

7 EOR and CCS

Though 100 years of oil and gas exploration most of the science and technology needed for CO_2 handling has been developed tested and matured on a large industrial scale. This includes process technology (*e.g.* CO_2 separation and transport), exploration (*e.g.* geology and geophysics), reservoir technology and monitoring. Enhanced oil recovery by CO_2 injection (CO_2 EOR) during 40 years has provided knowledge and experience on challenges specifically related to large scale handling of CO_2. At the present between 65 and 72 million tonne of CO_2 is injected annually in more than 130 projects ([49], [50]). This long effort has provided detailed knowledge of fluid properties and phase behavior of the CO_2/oil system at typical storage conditions, geochemical insight, corrosion, and HSE management. The performance of tertiary CO_2 flooding of mature oil reservoirs (CO_2 injection after the reservoir has been water flooded) is measured by the extra oil produced and this is typically ranging from 5 to 15 % relative to initial oil in place.

North America is the region where the large majority of the CO_2 EOR projected has been applied and most of the CO_2 comes from natural geological sources. More than 20 % of the injected CO_2 comes from industrial sources and in these cases the produced oil will actually have a lower CO_2 "footprint" compared to oil produced by conventional methods. In the world's largest CO_2 EOR project, the Wasson Denver Unit, more than 90 % of the injected CO_2 is actually permanently stored and also for other CO_2 EOR projects in North America the major part of injected CO_2 is stored [51]. The fugitive CO_2 in these cases comes from various processes during handling and recycling of CO_2. The emissions from these processes would likely be further reduced if suitable economic incentives were introduced. The environmental effects of CO_2 EOR can be much larger under a different economic framework. This has been illustrated by Holt et al. [52] were CO_2 injection was studied for 18 Norwegian and 30 UK water-flooded oil fields. The result showed that the projects gave a net storage of CO_2 even if the CO_2 from the combustion of the EOR oil produced was included.

Most of the natural CO_2 sources are already being exploited and if there will be a significant increase of CO_2 EOR in North America these projects will depend more and more on industrial CO_2 sources.

1. In the future CO_2 EOR can play an important role to reduce some barriers for applying CO_2 separation and storage in large scale. Because the value of CO_2 for enhanced oil recovery, the CO_2 price may cover a large part of the cost of separation and transport. During the first decades of CO_2 EOR the price varied from 9 to 24 USD/tonne varying with the oil price, while with the current oil price an economically viable CO_2 price for EOR has been estimated to be 40 to 44 USD/tonne [53].
2. The CO_2 EOR industry and future CCS could share common infrastructure for transport lowering the threshold for initializing large CCS projects and decrease transport cost.

8 Second and third generation technologies (2030 – 2050)

Main drawbacks of first generation CCS technologies are the higher cost of electricity and the increased fuel demand (typically 30%) due to the efficiency penalty (typically around 10-12%-points, as indicated in Figure 9). The impact is that CCS is being deemed incompatible with the economic development of some nations. Hence, in pursuing second generation technologies, efforts should be made to balance the *energy penalty* against the *emission index* in order to make CCS *affordable* and *economically sustainable*. This is an imperative approach, because several emerging economies will depend on the harnessing of indigenous coal in the foreseeable future (cf. Figure 10).

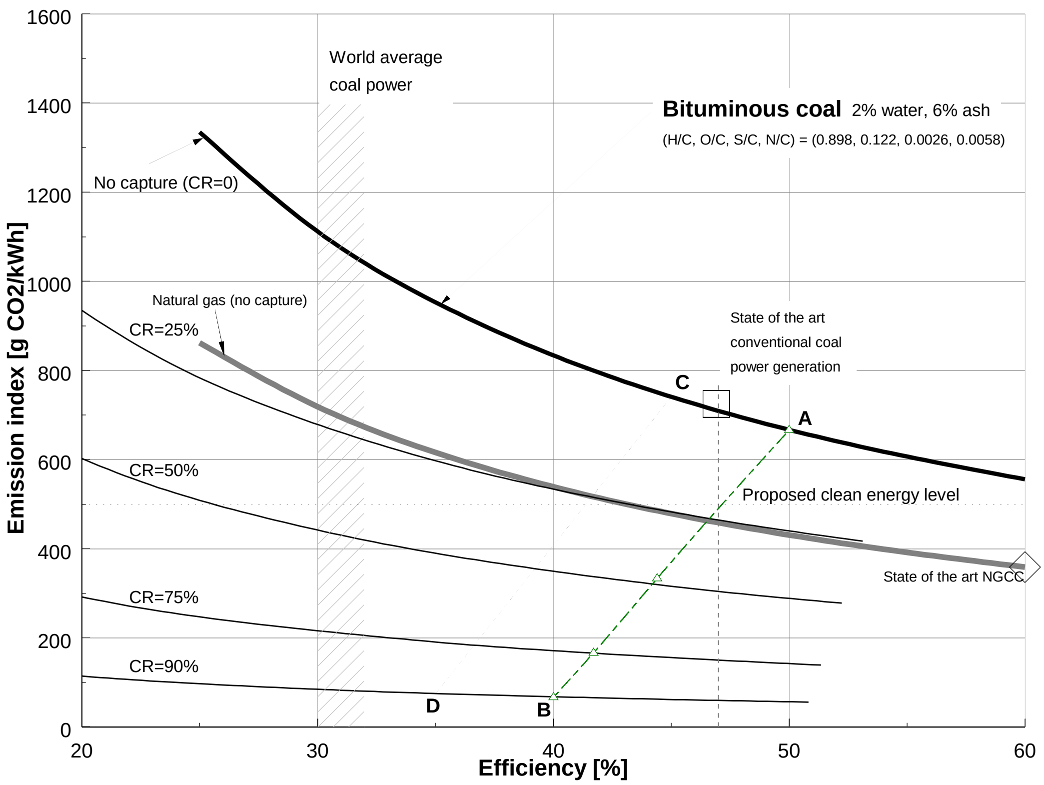


Figure 9: Emission index as a function of net plant electric efficiency with coal (capture rates – CR - in %) and natural gas power generation without CCS. Efficiency with current CCS technologies, as applied to highly advanced coal power generation, will drop by typically 10%-points, from C to D with 90% capture rate.

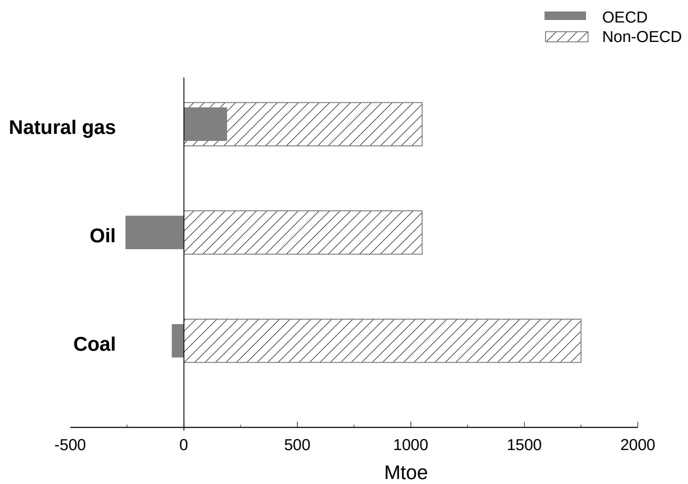


Figure 10: The annual demand for fossil fuels by year 2030 related to that of year 2007 in Mtoe (Source: Morgan, 2010, [54])

8.1 Transition and deployment of CCS at large

It is assumed that second generation CCS technologies will be needed in order to deploy CCS at large. One must expect that transition to CCS will impose changes beyond the technological dimension. Societal dimensions will be affected as well, especially infrastructural, political and institutional aspects. Inherent limitations, as to the rate of change, can be identified based on the perception that the energy system itself is so huge that it takes time to build the required human and industrial capacities [55]. The implication can be explained by two empirical laws of energy-technology development [56]:

1. A new (successful) energy technology tends to go through exponential growth until settling at a market share. Throughout the last century, the scale-up rate of successful technologies has typically been one order of magnitude per decade. And this exponential growth seems to continue until the technology becomes *material* – typically at around 1% of the total global energy mix.
2. After the technology has become *material* the growth is prone to shift from exponential to linear. This usually occurs when the technology settles at a market share.

Transition corresponds to the path from when the technology becomes *available* (delivering 1000 TJpa[6]) to the stage it becomes *material* (exceeding 10^6 TJpa) (cf. Figure 11). History suggests that a successful energy technology – at best – requires typically 30 years for reaching this stage. With CCS, in order to have the desired impact on the 2DS, the transition must be reduced to just one decade (cf. Figure 11, the broken line designated CCS) [55]. This unprecedented challenge requires targeted research aimed at second generation CCS technologies to be due for commercial operations no later than 2030, and third generation technologies to be enabled within 2050.

[6] This corresponds to a generating capacity of around 30 MW, depending on the time-based operational availability of the new technology.

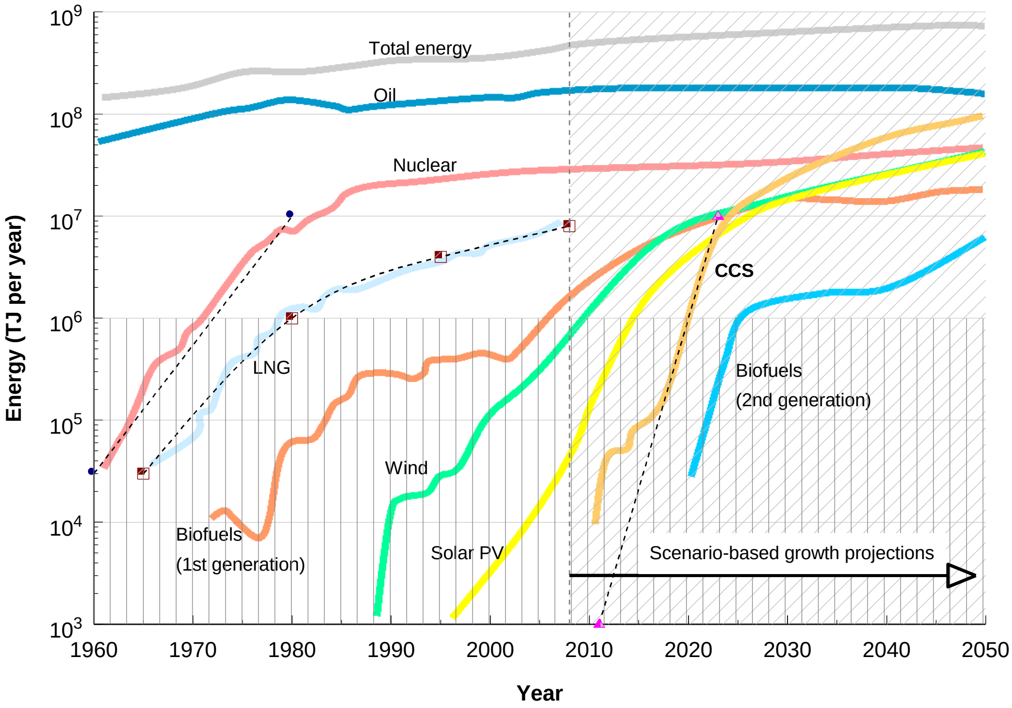


Figure 11: Relative importance of alternative energy technologies. (Source: Kramer & Haigh [56]).

Plausible technology development strategies should be based on priorities outlined in Figure 12. Here, the concept is refining the knowledge and experience of current CCS techniques via improvements of power cycles and emerging concepts, which will lead to second generation CCS. The strategy must be in favour of low energy penalties and ditto avoidance costs. The latter must be well below that of first generation technologies. The third generation technologies will opt for even lower energy penalties and avoidance costs. Although this approach envisages zero energy penalty, it should be kept in mind that zero energy penalty is a vision that cannot be reached. As a minimum, power must be sacrificed in order to compress the CO_2 to supercritical pressure (dense phase), as required to ensure safe geologic storage of the CO_2.

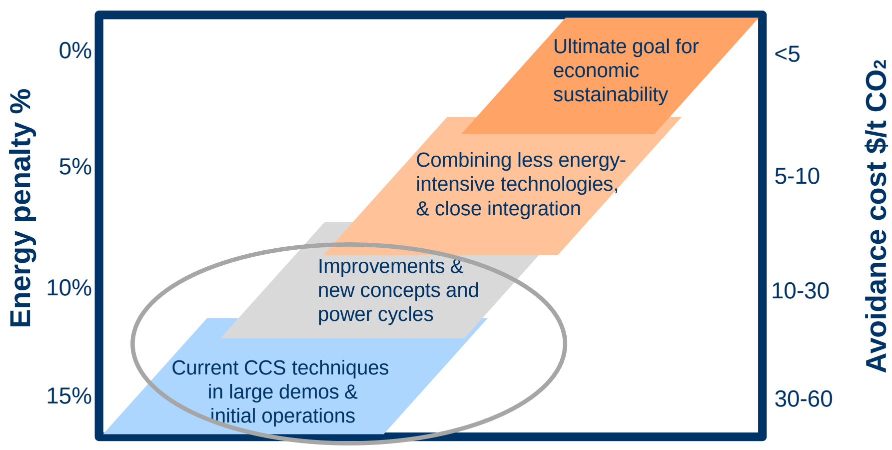


Figure 12: Priorities for CCS technology development [57].

Depending on the system and fuel composition, the concentration (or partial pressure) of CO_2 in off-gasses may vary significantly. As Figure 13 depicts, the theoretical separation work strongly depends on the CO_2 content. Typical volumetric CO_2 concentrations of conventional power cycles are 3.5% with natural gas combined cycles, and 14% with coal-fired steam cycles. Some industrial processes, however, combine large gas volumes and low CO_2 concentration (e.g. aluminium smelters), whereas other processes generate CO_2-rich off-gasses (cement and steel-making).

It is important to note that although the minimum separation work, as presented in Figure 13, is lower with pre-combustion capture than with post-combustion capture, the former applies to the producer gas only (typical of oxygen-blown gasifiers). It does not determine the energy penalty of a full pre-combustion process, as heat and power are sacrificed in other parts of the scheme. Only a complete analysis of the full systems can tell which case is the better one.

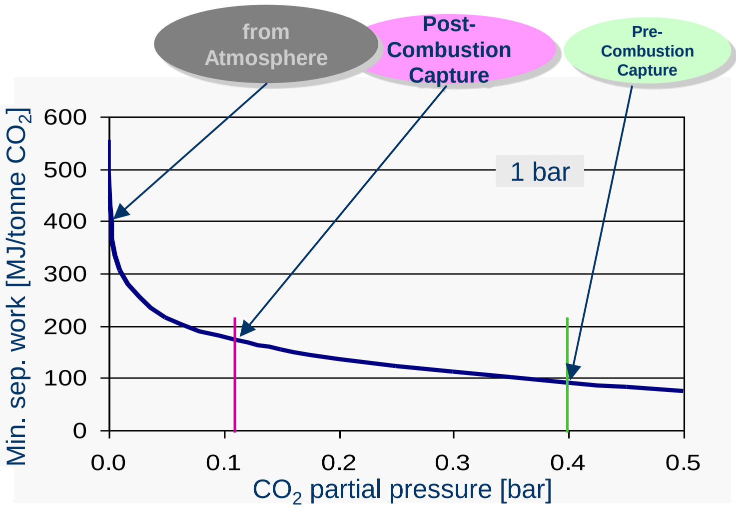


Figure 13: Theoretical minimum separation work of CO_2 from a flue gas depending on the partial pressure of CO_2. (Developed from data in [58]).

In consideration of CO_2 capture techniques, emphasis must be placed on two operational components that largely determine the energy penalty. This especially applies to a) separation work and b) compression work (cf. Figure 14). The two components represent the most significant gaps that are due for improvement in the future. Hence, a mention is made below on the theoretical minimum work versus the current state of development.

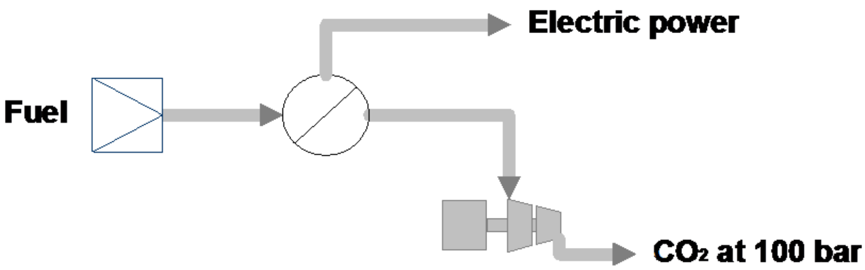


Figure 14: Generic CO_2 capture process.

8.1.1 Separation work

The minimum reversible separation work can be expressed by the following equation:

$$w_{sep,\, min} = -RT\Sigma y_i \ln y_i$$

where y_i is the volume fraction of component i in the mixture.

In order to reduce the separation work in practical operations, this equation suggests that low temperature of the gas should be strived at, combined with a high CO_2 concentration and low purity demand. Hence, as shown in Figure 13, a flue gas with 11% CO_2 concentration (~0.11 bar) will require a theoretical minimum separation work of 0.17 GJ/tonne CO_2. In contrast, the practical demand as of today – with amine-based separation technology – is in the range 3-3.5 GJ/tonne CO_2 (typical of MEA with steam-based regeneration), which is almost 20 times higher. This energy demand accounts for an efficiency drop of roughly 5-7%-points (depending on power cycle). The implication is that more efficient separation techniques are needed to reduce this technology gap.

8.1.2 CO_2 compression

The minimum reversible compression work can be expressed as follows:

$$w_{compr} = c_p T_1 [(p_1/p_2)^{(\kappa-1)/\kappa} - 1]$$

This equation suggests that the compression work is reduced by reducing the pressure ratio (i.e. keeping a high initial pressure, p_1) and lowering the inlet temperature of the gas (T_1). Hence, compressing CO_2 from 1 to 70 bar requires theoretically 48 kWh/tonne CO_2 (= 0.17 GJ/tonne CO_2). What is obtainable today in a four stage CO_2 compressor train with intercooling is about 93 kWh/tonne CO_2 (= 0.335 GJ/tonne CO_2) (with isentropic efficiency for each stage η_{is} = [0.85; 0.8; 0.75; 0.75]). In a coal power plant, this energy demand will account for a drop in plant efficiency of roughly 3 - 4.5%-points, depending on fuel composition and power cycle.

Hence, it is assumed that only marginal improvements can be achieved on compressor development. However, in consideration of new power cycles, process integration is an important aspect. The integration should strive at reducing the compression work (as already identified in Figure 2 with IGCC-CCS). In this context, pressurised power cycles are due to be looked at, especially oxy-combustion cycles and gasification technologies.

Compression also affects alternative systems such as chilled ammonia and freeze-out concepts as well as air separation units. In these systems, a high energy penalty is paid in order to provide the required cooling capacity, in which compression is a main contributor.

9 Integration of capture, transport and storage of CO_2 (from multiple sources)

In order for CCS to comply with the targeted greenhouse gas reduction, specific concerns and challenges are raised, as to the need for efficient and safe handling of the CO_2. The implication is that main components of CCS systems must be integrated and deployed in a swift manner and on a very large scale. Hence, a new infrastructure is required to connect CO_2 sources with CO_2 sinks. In the planning of this infrastructure, the amount of collectable CO_2 – from multiple single CO_2 sources and from CO_2 hubs or clusters – and the availability of storage capacity for the CO_2 must be taken into account to balance the volumes of CO_2 entering the system. At the outset, a simple CO_2 transport chain is likely to suffice. However, as adjacent CO_2 sources start feeding CO_2 into the chain, the complexity will grow. Later on, multiple CO_2 sources will be linked with several CO_2 sinks, thus forming a more comprehensive infrastructure comparable with natural gas distribution systems. A viable business model for operating a fully integrated CCS chain including storage remains to be developed. This model is still considered to be an unresolved challenge due to the handling of the commercial risks pertaining to uncertainty regarding emission trading, and the most pressing liability issue, as CO_2 must be kept safely trapped in geological formations for several thousand years [3].

Significant lessons can be learned from the integration of numerous EOR systems in the United States injecting CO_2 into oil reservoirs (CCUS). This applies to the entire EOR chain, having a direct bearing on CCS in projects using depleted oil and gas reservoirs. The composition of the impure CO_2 may, however, vary, depending on the purpose of the CO_2. Whether the CO_2 will be used for EOR or just stored in a saline formation will determine the specification pursuant to criteria based on operational, economical, safety and health issues. To some extent, these criteria may affect the upstream systems of the CCS chain. Important aspects will be the specification of these systems in order to ensure operational compliance, and to ensure chemical, metallurgical and geological integrity, as well as health, safety and environmental issues (HSE requirements).

Most likely, in an emerging CCS era, it is expected that in many densely populated regions, emphasis will at the outset be placed on remote geological formations. In Europe, for instance, this will probably be necessary in order to omit public concern and lengthy court cases, linked with land lease arrangements. Hence, a new infrastructure will be needed along with systems for the handling and transport of CO_2 from source to sink. As the number of sources tends to grow within the power sector and industries, and more storage sites are envisaged, a system must be drawn and optimised using computational models based on discrete nodes and connectors.

To cope with the vast volumes of CO_2 to be collected from future power plants and industrial clusters, pursuant to the 2DS, the transition to CCS needs a swift deployment within regions and across nations. This calls for a common basis to form the complete CCS chain. Preferably, this basis should refer to the same (or similar) guidelines, specifications and regulatory frameworks. The transport system of this infrastructure may include a pipeline for continuous conveyance, or tanks for intermittent transportation of the CO_2 stream (either by ship, rail or road). These options may, however, be combined, depending on the stage of development of each project. In consideration of alternatives full-chain integration concepts, the annual amount of CO_2, the transport cost, distance, or other societal and geographical constraints are key factors. In this equation, logistics and infrastructure development for CCS deployment at large constitutes cross-cutting issues linking the technical aspects.

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