Evaluating technology options to mitigate greenhouse gas emissions

Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass

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TOWARDS ZERO EMISSIONS CCS IN POWER PLANTS USING HIGHER CAPTURE RATES OR BIOMASS

Key Messages

- Fossil fuel power plants equipped with carbon capture and storage (CCS) need to demonstrate a pathway to zero CO_2 emissions if they are to have the same greenhouse gas footprint as competing new power generation technologies, such as renewables, and particularly if the technology is to contribute cost-effectively to a '2°C' or 'well below 2°C' scenario by the year 2100.
- Carbon dioxide (CO_2) capture rates from fossil fuel power plants applied in almost all integrated assessment models (IAMs), front-end engineering and design (FEED) studies, pilot plants, demonstration plants and technical analyses are currently based on a 90% capture rate cap, regardless of the technology type, the location or the fuel type.
- A literature review undertaken as part of this study exposes the 90% capture rate cap as an artificial limit. It is an historical benchmark, originally based on the economics of capture. The review indicated there were no technical barriers to increasing capture rates beyond 90% in the three classic capture routes (post-, pre- and oxyfuel combustion) and with the broad suite of CO_2 capture technologies currently available or under development.
- As CO_2 capture rates are increased, however, indirect emissions from fossil fuel use become significant, i.e. as the direct emissions tend to zero, the indirect emissions become proportionately greater. This is a factor to be managed in reducing overall CO_2 emissions, particularly in the fuel supply chains.
- This study provides a techno-economic analysis of a standard post-combustion capture (PCC) process applied to fossil fuel-fired power plants. It has revealed that, with dedicated process design, the additional costs of achieving essentially zero CO_2 emissions were quite modest in comparison with the costs of achieving 90% CO_2 capture. For 99.7%[1] CO_2 capture on an ultra-supercritical (USC) coal plant with CCS, the levelised cost of electricity (LCOE) increased by 7% and the CO_2 avoided cost by 3%. For 99%[1] CO_2 capture on an NGCC plant with CCS, the costs increased by 7% and 8%, respectively. It is essential that these findings are now demonstrated in practice.
- Where the achievement of high capture rates for a particular capture technology proves more challenging, either a hybrid capture approach or a combination with biomass co-combustion may offer more success.
- For coal-fired power stations, the option of using biomass co-combustion (10% biomass) combined with a standard PCC process (90% CO_2 capture) was the lowest cost option to achieve zero emissions, but is dependent on the region of deployment. The techno-economic study undertaken for this study indicated that, for a USC coal plant with CCS, the LCOE increased by 2% and the CO_2 avoided cost by 1.5%.
- Techno-economic analyses of other process routes and capture technologies need to be undertaken and, if warranted, validated by demonstration.

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[1] At this capture rate the power station is CO_2 neutral, i.e. the only CO_2 emitted is that in the incoming combustion air.

Background to the study

At COP 21 in December 2015, 195 countries signed a landmark treaty, the Paris Agreement, to strengthen the global response to climate change. The agreement sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to “well below 2°C” above pre-industrial levels. This target implies a carbon budget significantly more challenging than that required to meet a 2°C scenario, the previous objective and an appreciable target in itself. Modelling results have indicated that residual CO_2 emissions from fossil-fuel power stations fitted with CCS would be a limiting factor in the ability to restrict the global temperature increase to “well below 2°C” by the year 2100. In this study, pathways for fossil-fuel-fired power plants to achieve near-zero CO_2 emissions were explored

To-date, capture technology developers have largely focused on designing plant for capture rates of 85% to 90%, leaving 10-15% of the emissions uncaptured, which are usually referred to as residual emissions. Indeed, capture rates of 85%-90% appear to be ubiquitous in the CCS literature, being the values applied in almost all FEED studies, in most pilot and demonstration plants, and in much of the technical analysis undertaken.

In a “well below 2°C” scenario, it is projected that net zero carbon emissions would be required in the second half of this century. CO_2 capture rates will need to be much higher than design values currently in use. Given the continuing need for and use of fossil fuels, capture rates of 85%-90% fall well short of what would be needed to meet a “well below 2°C” carbon budget. Indeed, a recent IEAGHG study concluded that the 10%-15% residual emissions were “… likely to be really important in determining the extent of the role for fossil fuels with CCS especially in extremely emissions-constrained global scenarios" (IEAGHG, 2016)[2].

When considering the role of CCS and, consequently, what role “negative emissions technologies” (or NETs) will have to play, it will be important to understand the limits that apply to CO_2 capture rates. To achieve the low net CO_2 emissions consistent with a “well below 2°C” scenario, models currently place great emphasis on NETs. In theory, there are several NETs that have the potential to lower atmospheric CO_2 levels, examples being afforestation, direct air capture, and bio-energy with CCS (BECCS). Each of these, however, brings its own challenges.

In this study the technological, economic, environmental and political barriers to moving towards zero CO_2 emissions from fossil fuel-based power generation plants have been investigated. Accordingly, the potential to improve CO_2 capture rates above the customary 85%-90% have been explored across the full range of capture technologies. Additionally, as the use of biomass in combination with CCS, e.g. by co-firing (or co-gasifying), could also be used to achieve net zero (or net negative) emissions, this has also been explored. In practice, biomass might be deployed instead of or in addition to raising capture rates to achieve the emissions reductions sought. While BECCS has been considered in the study, technologies that do not seek to reduce CO_2 emissions from the flue or fuel gas streams of fossil-based power generation plants, such as afforestation and direct air capture, have been excluded.

The study was undertaken by a team at CSIRO led by Dr. Paul Feron.

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[2] IEAGHG, “Can CO_2 Capture and Storage Unlock ‘Unburnable Carbon’?”, 2016/05, May 2016.

Scope of Work

Progress towards zero emissions of CO_2 from fossil-fuel fired power plants may be realised by increasing CO_2 capture rates, by replacing fossil fuels with biomass-based fuels or by applying some combination of the two. While all were explored, the option of increasing CO_2 capture rates has received less attention in the past and is the major focus in this study.

A literature review was undertaken, followed by an investigation of capture rates used in experimental and modelling practice, with a focus on actual projects and FEED studies. The outcomes of studies considering higher capture rates were reviewed, including a previous study carried out by the IEA Greenhouse Gas R&D Programme (IEAGHG, 2006)[3]. The use of capture rates in integrated assessment models (IAMs) was investigated. In the context of increasing CO_2 capture rates towards zero emissions, it was considered relevant to examine the relative contributions of direct and indirect greenhouse gas emissions from power plants.

A review of literature on the use of biomass for reducing CO_2 emissions was undertaken and the potential of current capture technologies to adopt higher capture rates considered.

Finally, with amine based CO_2 capture technologies now being deployed at existing power stations, a detailed investigation on the impact of increasing capture rates on the techno-economic performance of a power plant equipped with this technology was carried out.

Findings of the Study

CO_2 capture rates used in practice

In the two large-scale CCS projects operating at present in the power industry (the Boundary Dam and PetraNova projects), 90% of the CO_2 is captured from the flue gas directed to the capture plant. The 15 FEED studies and other advanced project initiatives examined also indicated a prevalence of 90% CO_2 capture, irrespective of the capture technology used. A general assessment of previous studies by IEAGHG and others had indicated that increasing capture rates beyond 90% can significantly increase costs, with the lowest impact being on oxyfuel combustion and the highest for post-combustion capture (PCC).

IAMs base their information on CCS systems in previous studies and technology assessments that commonly employ a 90% capture rate as the average, resulting in 10% residual CO_2 emissions from a power plant fitted with CCS technology. Some earlier studies are based on 85% CO_2 capture.

Increasing the rate of CO_2 capture

The rate of CO_2 capture can be increased in all the three classic capture routes – post-combustion, pre-combustion and oxyfuel combustion – in different ways. For post-combustion CO_2 capture, the only path is through increasing the effectiveness of the CO_2 separation process. For oxyfuel combustion, CO_2-slip occurs primarily via the vent gases. The amount of venting can be reduced by avoiding the build-up of inerts, achieved by using higher purity oxygen and allowing less air ingress into the boiler. CO_2 can also be recovered from these vent gases. For pre-combustion capture, CO_2-slip with the flue gas can be limited by a higher carbon conversion and a more effective CO_2 separation process. No technological limitation to the

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[3] IEA GHG, "Near zero emission technology for CO_2 capture from power plant", 2006/13, October 2006.

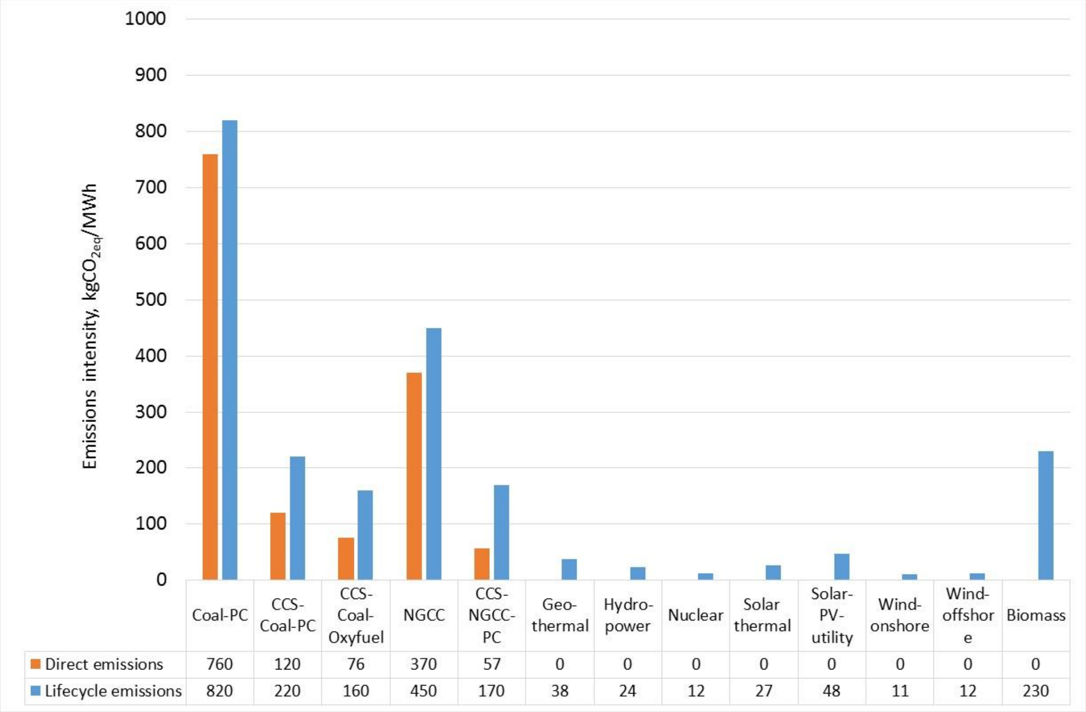
increase of CO_2 capture rates were identified, with any limitations likely to emerge from a techno-economic optimisation.

Most detailed techno-economic optimisation studies have involved amine-based post-combustion capture. These generally indicate a 5% increase in the cost per tonne of CO_2 avoided when moving from 90% to 99% CO_2 capture. However, the literature also indicated divergent views. A previous IEAGHG study (IEAGHG, 2006)[2] indicated a much larger increase than 5% in the cost per tonne of CO_2 avoided for amine-based CO_2 capture technology. It was concluded therefore that a detailed study was needed to estimate the impact of increasing CO_2 capture rate. The focus of this study was on amine-based post-combustion capture technology, as this is the leading technology for implementation in power plants.

Direct and indirect emissions of greenhouse gases

A variation in the CO_2 capture rate will impact on the direct and indirect greenhouse gas emissions from a fossil-fuel-fired power station in different ways. Without CO_2 capture, the direct emission intensity (kg CO_2/MWh) is proportionally dependent on the carbon content of the fuel and inversely proportional to the energy conversion efficiency. The direct emissions intensity will be reduced in power plants with CCS to a lesser degree than the capture rate, as the energy requirement of the capture process will decrease the efficiency of the power station. The indirect emission intensity depends on the fuel type, the energy conversion efficiency and industrial practices used throughout the fuel chain. As a result the indirect emission intensity can vary considerably.

Using data from the Intergovernmental Panel on Climate Change's (IPCC's) 5th Assessment Report (AR5), direct and lifecycle emissions based on median emission values were estimated for a range of energy technologies as shown in Figure 1.



	Coal-PC	CCS-Coal-PC	CCS-Coal-Oxyfuel	NGCC	CCS-NGCC-PC	Geo-thermal	Hydro-power	Nuclear	Solar thermal	Solar-PV-utility	Wind-onshore	Wind-offshore	Biomass
🟧 Direct emissions	760	120	76	370	57	0	0	0	0	0	0	0	0
🟦 Lifecycle emissions	820	220	160	450	170	38	24	12	27	48	11	12	230

Figure 1: Direct and lifecycle emission intensity for a range of energy supply technologies (median values).

For indirect emissions from gas and coal-fired power plants, the impact of increasing the capture rates from 90% to 99% on emission intensity was assessed. Implementing 99% CO_2 capture would reduce the direct emissions intensity to levels that are lower than to those found in AR5 for both renewable energy and nuclear energy generation (9 kg CO_{2eq}/MWh_e for coal; 4 kg CO_{2eq}/MWh_e for gas). However, at 99% CO_2 capture the indirect emissions constitute 81% of the total emissions intensity for a coal-fired power station and 96% for a natural gas-fired combined cycle, and the total emission intensity is still higher than for renewable or nuclear energy generation (48 kg CO_{2eq}/MWh_e for coal; 89 kg CO_{2eq}/MWh_e for gas). To maximise the benefits of higher CO_2 capture rates in providing a path towards zero emissions, increasing the capture rate should therefore go hand-in-hand with efforts to reduce fugitive emissions from coal and gas.

The use of a renewable energy source to supply the capture energy requirement was found to be beneficial for reducing CO_2 emissions as the efficiency reduction from the capture process was avoided. In a gas-fired combined cycle, the emission intensity was brought down to 78 kg CO_{2eq}/MWh_e. For a coal-fired power plant, the emissions intensity was reduced to 44 kg CO_{2eq}/MWh_e.

Use of biomass

Although biomass is an important source of the world's primary energy requirements, only a small portion (~4%) of bioenergy is used for power generation globally. Combustion is the dominant and proven technology for (heat and) power generation from biomass. Co-firing biomass in existing coal-fired power plants is a simple and effective way to reduce CO_2 emissions. In this process woody biomass (wood chips and wood pellets) is blended with coals, commonly in the range of 5−15 percent of total energy input and directly co-fired in an existing coal-fired boiler. The added costs associated with modification, operation and maintenance are small compared to the costs associated with fuel handling, processing, storage and the feed system. The milling of biomass is an important step in a large-scale co-firing system. It is also essential to select biomass with a low mineral matter content and a relatively higher fusion temperature.

Biomass gasification can provide higher efficiency with product flexibility. There are, however, technological barriers for biomass gasification, which mainly include tar reduction, gas cleaning and scale-up. The most promising approach for large-scale commercial application is indirectly co-fired syngas from biomass gasification in the existing coal-fired boilers, as the boiler is not sensitive to the purity or quality of biomass-derived syngases.

Capture technologies

The capture of CO_2 from flue gases or other power plant gas streams, such as CO_2/H_2 or CO_2/O_2 mixtures, requires a separation process that can use physical or chemical means. Physical means can include phase change through temperature change, difference in solubility or diffusion through materials, while chemical means can include chemical reaction with solid or liquid agents.

Amine-based CO_2 capture is able to produce a pure CO_2 product at any desirable capture rate. The only limitation is the economic feasibility as the CO_2 capture rate is varied. A wide range of alternative and emerging capture technologies, including membranes, solid sorbents, chemical looping processes and refrigeration, were qualitatively assessed. The literature review indicated that most studies had focused on a common capture rate of 85-90%. Achieving higher capture rates is not only determined by the capture agent or principle, but also by the process operation.

Polymeric membrane technology lends itself least to higher capture rates. Other more selective membrane technologies would be able to achieve higher capture rates, particularly for high-pressure gas streams such as those in pre-combustion CO_2 capture.

For solid sorbent technology, there is likely to be a trade-off with the CO_2 purity; i.e. at a high capture rate the purity will decrease. A highly selective solid sorbent, e.g. based on a chemical interaction with the substrate, will be less affected by this issue.

Chemical looping processes are based on a chemical interaction between the gases and solids mostly in circulating fluidised-bed processes. CO_2-slip can occur between the two reactors and limit the achievement of very high capture rates.

In general, the suite of possible capture technologies (agents and processes) is amenable to capture rates higher than 90%. Overall detailed assessments of the impact of CO_2 capture on technologies other than amine-based absorption processes are, however, lacking and it is not clear at what capture rate the techno-economic optimum lies. It should be borne in mind that hybrid options, i.e. cost-effective combinations of different CO_2 capture technologies, may also be applied.

Cost implications for power stations

The implications of increasing capture rates on the costs of power generation and CO_2 emission reduction were assessed in detail for PCC on an ultra-supercritical (USC) pulverised coal-fired power station and a natural gas-fired power station using a standard amine technology based on 30% aqueous monoethanolamine (MEA) solution. Using different PCC plant designs, the technical and economic performance parameters were assessed at capture rates $\geq$90%. For the USC coal-fired power station, the option of 10% biomass co-combustion was also included. For both power plant types, the capture rate at which the power plant was CO_2 neutral, i.e. where the power plant only emits an amount of CO_2 equal to the amount present in the incoming combustion air, was also determined and the techno-economic performance assessed at that capture rate. The tables below provide a summary for both types of fossil fuel fired power stations.

Table 1: Summary techno-economic assessment for an ultra-supercritical pulverised coal fired power station with PCC at different CO_2-capture rates

		USC PC plant with PCC					
	USC PC plant without PCC	**Standard PCC plant design**			**PCC plant with inter-cooling + rich split**		**10% biomass co-fired + PCC plant**
		90%	**95%**	**99%**	**99%**	**99.7%**[4]	**90%**
Gross power output (MW)	900	900	900	900	900	900	900
Net power output (MW)	817	633.9	623.3	600.7	617.5	606.5	633.9
Net plant HHV efficiency (%)	42.5	32.97	32.42	31.24	32.11	31.54	32.97
Net plant LHV efficiency (%)	44.4	34.48	33.91	32.68	33.59	32.99	34.48
CO_2 emission intensity (t/MWh$_e$)	0.736	0.092	0.045	0.007	0.007	0.000	0.000
Equivalent electrical energy consumption (MWh$_e$/t CO_2)	-	0.337	0.338	0.362	0.334	0.350	0.337
Specific capital requirement (€/kW$_{net}$)[5]	1647	2654	2712	2830	2759	2813	2704
LCOE (€/MWh)[6]	51.6	87.0	89.7	94.0	91.5	93.4	88.7
CO_2 avoided cost (€/t CO_2)	-	55.0	55.2	58.3	54.8	56.9	55.8

Increasing the CO_2 capture rate beyond 90% in a standard PCC plant on a USC pulverised coal fired power station results in a further efficiency decrease and a modest increase in capital cost and electricity generation cost. The efficiency decrease and capital cost increase can be offset by the adoption of PCC process design modifications, such as intercooling and rich split flow. Overall, a USC pulverised coal fired power station can be made CO_2 neutral (99.7% capture) by increasing the cost of electricity generation by 7% compared with the cost at 90% capture rate, with only a 3% increase in CO_2 avoided cost. However, the co-combustion of 10% biomass with 90% CO_2 capture is the most economic option to achieve zero emission, with a 2% increase in electricity generation cost and a 1.5% increase in CO_2 avoided cost.

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[4] At this capture rate, the USC coal-fired power station is CO_2 neutral, i.e. the only CO_2 emitted is that in the incoming combustion air.

[5] Costs for the year 2015.

[6] Fuel costs are €2.5/GJ for coal, €3.2GJ for biomass.

Table 2: Summary techno-economic assessment for a natural gas fired combined cycle with PCC at different CO_2 capture rates

	NGCC without PCC	NGCC with PCC		
		Standard PCC plant design		
		90%	95%	99%[7]
Gross power output (MW)	890	890	890	890
Net power output (MW)	878	728	720	691
Net plant HHV efficiency (%)	52.66	43.91	43.37	41.94
Net plant LHV efficiency (%)	58.25	48.57	47.97	46.39
CO_2 emission intensity (t/MWh$_e$)	0.349	0.0372	0.0176	0.000
Equivalent electrical energy consumption (MWh$_e$/t CO_2)	-	0.523	0.526	0.583
Specific capital requirement (€/kW$_{net}$)[8]	939	1611	1629	1716
LCOE (€/MWh)[9]	52.9	77.6	78.9	82.7
CO_2 avoided cost (€/t CO_2)	-	79.3	78.6	85.5

The increase in CO_2 capture rate over the usual 90% in a standard PCC plant on a natural gas-fired combined cycle plant results in a further efficiency decrease and a limited capital cost and electricity generation cost increase. Overall, a natural gas fired combined cycle can be made CO_2 neutral (99% capture) at a 7% electricity generation cost increase over the baseline 90% capture case with an 8% increase in cost of CO_2 avoided. The use of different PCC process designs was not effective in improving efficiency and costs for the natural gas-fired combined cycle plant.

At the fuel costs assumed for the analysis, the cost of electricity for the gas-fired combined cycle with PCC are lower than for the USC pulverised coal fired power station with PCC. Conversely, however, the CO_2 avoided costs for the USC pulverised coal-fired power station are lower than for the gas-fired combined cycle plant.

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[7] At this capture rate, the natural gas fired combine cycle is CO_2-neutral, i.e. the only CO_2 emitted is that in the incoming combustion air.

[8] Cost for the year 2015.

[9] Fuel costs are 5€/GJ for gas.

Expert Review Comments

A review was undertaken by a number of international experts. The draft report was generally well received, with reviewers remarking on its valuable contribution to an important topic that has been underexplored.

A large number of comments and suggestions were made by the reviewers, all of which were addressed by the authors. Where appropriate, corrections and additions were either made to the text. In some cases, it was recognised that some recommendations lay outside the scope of the study.

Conclusions

The study found that CO_2 capture rates applied in almost all FEED studies, pilot plants, demonstration plants and technical analyses were based on 90% regardless of the technology type, the location or the fuel type.

A review of the literature indicated that there were no technical barriers to increasing capture rates in the three capture routes (post-, pre- and oxyfuel combustion) and with the broad suite of CO_2 capture technologies currently available or under development. Where a particular capture technology proves less capable of achieving higher capture rates, either a hybrid capture approach or a combination with biomass co-combustion might offer more success.

Furthermore, it was found that, as CO_2 capture rates were increased, the indirect emissions from fossil fuel use became dominant. Using literature data to estimate the indirect emissions for the chosen fuels, this was identified to be a significant barrier to reducing overall CO_2 emissions, particularly in gas-fired power stations.

Techno-economic analysis of a standard PCC process applied to fossil fuel-fired power plants revealed that, with dedicated process design, the additional costs of achieving essentially zero CO_2 emissions were quite modest in comparison with the costs of achieving 90% CO_2 capture in the first place. For coal-fired power stations, the option of using biomass co-combustion (10% biomass) combined with a standard PCC process (90% CO_2 capture) was the lowest cost option.

Recommendations

Zero CO_2 emission power generation technologies, as a key element of the mix of low emission technologies, are needed if greenhouse gas emissions are to be addressed effectively. CCS needs to have near-zero emissions to have same greenhouse gas footprint as competing new power generation technologies. In their absence, the target of limiting global atmospheric warming to ‘well below 2°C’, let alone ‘2°C’, becomes more difficult and more costly.

As the power sector has increasing access to generation options such as nuclear and renewable energy with zero direct CO_2 emissions, more attention needs to be directed at zero emissions from fossil fuel power plants using CCS. While a comprehensive review of the literature and desktop modelling studies indicate that, when fitted with CCS, there are no technological barriers to achieving near-zero emissions from both coal and gas-fired power plants, validation is required. **Higher capture rates urgently need to be demonstrated in practice across the range of capture technologies.**

The immediate pathway towards zero emission power plants is the combination of amine-based CCS with biomass co-firing, and the demonstration of such power plants should be pursued.

The techno-economic optimisation of CO_2 capture technologies other than amine-based technologies for PCC as a function of the CO_2 capture rate is needed to underpin the availability of a wider range of options. Chemical looping technologies are a good example, but also hybrid capture options or other capture options in combination with biomass co-combustion deserve further assessment.

The reduction of indirect emissions associated with the use of coal and gas are of similar urgency and should be pursued with vigour as part of the zero emission fossil fuel pathway.

Suggestions for further work

The findings from this study provide the basis for the following recommendations:

- There needs to be wider communication within the broader energy community of the ability of CCS to achieve near-zero emissions. While the capture rate is carefully selected according to the performance required of a particular plant, no artificial limit should automatically be assumed. Notably, the ubiquitous use of 90% for capture rate in models looking at long-run climate change scenarios explicitly places an artificial limit on the capability of the technology.
- The validation in practice of near-zero emissions CCS is required. With specific design modifications, desktop modelling studies show that near-zero emissions can be achieved with amine-based capture on a PCC unit at a modest cost increase over the cost of achieving 90% capture. Thus, from a technical point of view, increasing capture rates above 90% does not increase costs significantly as previously thought. Moreover, adding co-combustion with biomass can achieve zero emissions at a lower cost.
- A techno-economic assessment of other process routes and capture technologies is needed. Higher capture rates urgently need to be demonstrated across the range of capture technologies. A comprehensive review of the literature indicates that there are no technological barriers to achieving near-zero emissions from a range of capture technologies.
- The demonstration of zero emissions by combining amine-based CCS with biomass co-firing should be pursued.
- The reduction of indirect emissions associated with the use of coal and gas to generate power are of similar urgency and should be pursued with vigour as part of the zero CO_2 emissions fossil fuel pathway.

Towards zero emissions CCS in power plants using higher capture rates or biomass

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Executive summary

Aim

This study considered pathways for fossil-fuel-fired power plants to achieve zero emissions of carbon dioxide. The rationale for this study came from the observation of results from integrated assessment models, particularly those aiming to limit global temperature increase to 2 degrees Celsius or well below 2 degrees Celsius by the year 2100. These observations indicated that the residual emissions from fossil-fuel power stations represented a significant CO_2 emission that needed to be addressed.

Approach

Progress towards zero emissions of carbon dioxide from fossil-fuel fired power plants can be realised in two ways: increasing CO_2 capture rates or replacing fossil fuels with biomass-based fuels. The option of increasing CO_2 capture rates has received less attention and is a major focus here.

The study first investigated the capture rates used in experimental and modelling practice, with a focus on actual projects and FEED (Front End Engineering & Design) studies. The outcomes of studies considering higher capture rates were reviewed, including a previous study carried out by the IEA Greenhouse Gas R&D Program (IEAGHG 2006), followed by an investigation into the use of capture rates in integrated assessment models. In the context of increasing CO_2 capture rates, we considered it relevant to examine the differentiation between direct and indirect greenhouse gas emissions from power plants.

The study also reviewed the literature on the use of biomass for reducing CO_2 emissions and considered the potential of current capture technologies to adopt higher capture rates.

Finally, with amine based CO_2 capture technologies now being deployed at existing power stations on a large scale, we carried out a detailed investigation on the impact of increasing capture rates on the techno-economic performance of a power plant equipped with this technology.

CO_2 capture rates used in practice

In the two large scale CO_2 capture and storage (CCS) projects in the power industry (Boundary Dam and PetraNova projects), 90% of the CO_2 is captured from the flue gas that is directed to the capture plant. FEED studies also indicate a prevalence of 90% CO_2 capture, irrespective of the capture technology used. A general assessment of previous studies indicated that increasing capture rates beyond 90% can significantly increase costs, with the lowest impact being on oxyfuel and the highest for post-combustion CO_2 capture (PCC).

Integrated assessment models base their information on CCS systems in previous studies and technology assessments that commonly employ a 90% capture rate as the average, resulting in residual CO_2 emissions from a CCS technology chain. Earlier studies are sometimes based on 85% CO_2 capture.

Increasing the rate of CO_2 capture

The rate of CO_2 capture can be increased in the three capture routes - post-combustion, pre-combustion and oxyfuel - in different ways. For post-combustion CO_2 capture, the only path is through increasing the effectiveness of the CO_2-separation process. For oxyfuel CO_2-slip occurs primarily via the vent gases. The amount of venting can be reduced by avoiding the build-up of inerts (higher purity oxygen, less air ingress in boiler). CO_2 can also be recovered from these vent gases. For pre-combustion capture, CO_2-slip with the flue gas can be limited by a higher carbon conversion and a more effective CO_2-separation process. No technological limitation to the increase of CO_2 capture rates has been identified and limitations will likely emerge from a techno-economic optimisation.

Most detailed techno-economic optimisation activities have involved amine-based post-combustion CO_2 capture. These generally indicate a 5% increase in the cost per tonne of CO_2 emissions reduced when moving from 90% to 99% CO_2 capture. However, the literature also indicated divergent views. A previous IEAGHG study indicated a much larger increase in cost per tonne of CO_2 emission avoided for amine-based CO_2 capture technology. We therefore concluded that a detailed study was needed to estimate the impact of increasing CO_2 capture rate. Our focus is on amine-based post-combustion CO_2 capture technology, as this is the leading technology for implementation in power plants.

Direct and indirect emissions of greenhouse gases

A variation of the CO_2 capture rate will impact on the direct and indirect greenhouse gas emissions from a fossil-fuel-fired power station in different ways. Without CO_2 capture, the direct emission intensity is proportionally dependent to the carbon content of the fuel and inversely proportional to the energy conversion efficiency. The direct emissions intensity will be reduced in power plants with CCS, but to a lesser degree than the capture rate, as the energy requirement of the capture process will decrease the efficiency of the power station. The indirect emission intensity depends on the fuel type, the energy conversion efficiency and industrial practices used throughout the fuel chain. As a result the indirect emission intensity varies considerably.

Using data from the fifth Intergovernmental Panel on Climate Change (IPCC) assessment report for indirect emissions from gas and coal-fired power plants based on median indirect emission values for the two fuels, we assessed the impact of increasing the capture rates from 90% to 99% on emission intensity. Implementing 99% CO_2 capture will reduce the direct emissions intensity to levels that are lower than to those found in the fifth IPCC assessment report for renewable energy and nuclear energy generation (9 kg CO_2eq/MWh_e for coal; 4 kg CO_2eq/MWh_e for gas). However, at 99% CO_2 capture the indirect emissions constitute 81% of the total emissions intensity for a coal-fired power station and 96% for a natural gas-fired combined cycle, and the total emission intensity is still higher than for renewable or nuclear energy generation (48 kg CO_2eq/MWh_e for coal; 89 kg CO_2eq/MWh_e for gas). To maximise the benefits of higher CO_2 capture rates in providing a path towards zero emissions, increasing the capture rate should therefore go hand-in-hand with efforts to reduce fugitive emissions from coal and gas.

The use of a renewable energy source to supply the capture energy requirement was beneficial for reducing CO_2-emissions as the efficiency reduction from the capture process was avoided. In a gas-fired combined cycle the emission intensity was brought down to 78 kg CO_2eq/MWh_e. For a coal-fired power plant, the emissions intensity was reduced to 44 kg CO_{2eq}/MWh_e.

Use of biomass

Although biomass is an important source of the world's primary energy requirements, only a small portion (~4%) of worldwide bioenergy is used for power generation. Combustion is the dominant and proven technology for (heat and) power generation from biomass. Co-firing biomass in existing coal-fired power plants is a simple and effective way to reduce CO_2 emissions. In this process woody biomass (wood chips and wood pellets) can be blended with coals, commonly in the range of 5−15 percent of the total energy input and directly co-fired in an existing coal-fired boiler. The added cost associated with modification, operation and maintenance is small compared to the cost associated with fuel handling, processing, storage and the feeding system. Milling of biomass is an important step in a large scale co-firing system. It is also essential to select biomass with a low content of mineral matter with relatively higher fusion temperature.

Biomass gasification can provide higher efficiency with product flexibility. Technological barriers for biomass gasification mainly include tar reduction, gas cleaning and scale-up. The most promising approach for large scale commercial application is indirectly co-fired syngas from biomass gasification in the existing coal-fired boilers, as the boiler is not sensitive to purity and quality of biomass-derived syngases.

Capture technologies

The capture of CO_2 from flue gases or other power plant gas streams, such as CO_2/H_2 or CO_2/O_2 mixtures, requires a separation process that can use physical or chemical means. Physical means can include phase change through temperature change, difference in solubility or diffusion through materials, while chemical means can include chemical reactions with solid or liquid agents.

Amine-based CO_2 capture is able to produce a pure CO_2 product at any desirable capture rate. The only limitation is the economic feasibility as the CO_2 capture rate is varied. We qualitatively assessed a wide range of alternative and emerging capture technologies, including membranes, solid sorbents, chemical looping processes and refrigeration. The literature review indicated that most studies have focused on a common capture rate of 85-90%. Achieving higher capture rates is not only determined by the capture agent or principle, but also by the process operation.

Polymeric membrane technology lends itself least for higher capture rates. Other more selective membrane technologies will be able to achieve higher capture rates, particularly for high-pressure gas streams such as those in pre-combustion CO_2 capture.

For solid sorbent technology, there is likely to be a trade-off with the CO_2-purity; i.e. at a high capture rate the purity will decrease. A highly selective solid sorbent, e.g. based on a chemical interaction with the substrate, will be less affected by this issue.

Chemical looping processes are based on a chemical interaction between the gases and solids mostly in circulating fluidised-bed processes. CO_2-slip can occur between the two reactors and limit the achievement of very high capture rates.

In general, we conclude that the suite of capture technologies (agents and processes) is amenable to capture rates higher than 90%. Overall detailed assessments of the impact of CO_2 capture on technologies other than amine based absorption processes are, however, lacking and it is not clear where the techno-economic optimum lies. One should bear in mind that hybrid options, i.e. cost-effective combinations of different CO_2 capture technologies, can also be applied.

Cost implications for power stations

The implications of increasing capture rates for the costs of power generation and CO_2-emission reduction were assessed in detail for PCC on a ultra-supercritical pulverised coal fired power station and a natural gas fired power station using the standard amine technology based on a 30% aqueous monoethanolamine solution. Using different PCC plant designs, the technical and economic performance parameters were assessed at capture rates ≥ 90%. For the supercritical coal fired power station the option of 10% biomass co-combustion was also included. For both power plant types, the capture rate at which the power plant was CO_2-neutral, i.e. where the power plant only emits an amount equal to the amount of CO_2 present in the incoming combustion air, was also determined and the techno-economic performance assessed at that capture rate. The tables below provide a summary for both types of fossil fuel fired power stations.

Summary techno-economic assessment for an ultra-supercritical pulverised coal fired power station with PCC at different CO_2-capture rates

		USC PC plant with PCC					
	USC PC plant without PCC	**Standard PCC plant design**			**PCC plant with inter-cooling + rich split**		**10% biomass co-fired + PCC plant**
		90%	**95%**	**99%**	**99%**	**99.7%**[1]	**90%**
Gross power output (MW)	900	900	900	900	900	900	900
Net power output (MW)	817	633.9	623.3	600.7	617.5	606.5	633.9
Net plant HHV efficiency (%)	42.5	32.97	32.42	31.24	32.11	31.54	32.97
Net plant LHV efficiency (%)	44.4	34.48	33.91	32.68	33.59	32.99	34.48
CO_2 emission intensity (t/MWh_e)	0.736	0.092	0.045	0.007	0.007	0.000	0.000
Equivalent electrical energy consumption ($MWh_e/t\ CO_2$)	-	0.337	0.338	0.362	0.334	0.350	0.337
Specific capital requirement ($€/kW_{net}$)[2]	1647	2654	2712	2830	2759	2813	2704
LCOE (€/MWh)[3]	51.6	87.0	89.7	94.0	91.5	93.4	88.7
CO_2 avoided cost (€/t CO_2)	-	55.0	55.2	58.3	54.8	56.9	55.8

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[1] At this capture rate the supercritical coal fired power station is CO_2-neutral, i.e. the only CO_2 emitted is that in the incoming combustion air.

[2] Costs for the year 2015.

[3] LCOE = levelised cost of electricity; Fuel costs are 2.5€/GJ for coal, 3.2€GJ for biomass

The increase in CO_2-capture rate over the usual 90% in a standard PCC plant on an ultra-supercritical pulverised coal fired power station results in a further efficiency decrease and modest increase in capital cost and electricity generation cost. The efficiency decrease and capital cost increase can be improved upon by the adoption of PCC process design modifications, such as intercooling and rich split. Overall, an ultra-supercritical pulverised coal fired power station can be made CO_2-neutral (99.7% capture) at a 7% electricity generation cost increase over the usual 90% capture rate with only a 3% increase in CO_2 avoided cost. The co-combustion of 10% biomass in the coal fired power station with 90% CO_2-capture is the most economical option with a 2% increase in electricity generation cost over the usual 90% capture rate and only 1.5% increase in CO_2 avoided cost.

Summary techno-economic assessment for a natural gas fired combined cycle with PCC at different CO_2-capture rates

	NGCC without PCC	NGCC with PCC		
		Standard PCC plant design		
		90%	**95%**	**99%**[4]
Gross power output (MW)	890	890	890	890
Net power output (MW)	878	728	720	691
Net plant HHV efficiency (%)	52.66	43.91	43.37	41.94
Net plant LHV efficiency (%)	58.25	48.57	47.97	46.39
CO_2 emission intensity (t/MWh_e)	0.349	0.0372	0.0176	0.000
Equivalent electrical energy consumption ($MWh_e/t\ CO_2$)	-	0.523	0.526	0.583
Specific capital requirement (€/kW_{net})[5]	939	1611	1629	1716
LCOE (€/MWh)[6]	52.9	77.6	78.9	82.7
CO_2 avoided cost (€/t CO_2)	-	79.3	78.6	85.5

The increase in CO_2-capture rate over the usual 90% in a standard PCC plant on a natural gas fired combined cycle results in a further efficiency decrease and a limited capital cost and electricity generation cost increase. Overall, a natural gas fired combined cycle can be made CO_2-neutral (99% capture) at a 7% electricity generation cost increase over the usual 90% capture rate with an 8% increase in CO_2 avoided cost. The use of different PCC process designs was not effective in improving efficiency and costs for the natural gas fired combined cycle.

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[4] At this capture rate the natural gas fired combine cycle is CO_2-neutral, i.e. the only CO_2 emitted is that in the incoming combustion air.

[5] Cost for the year 2015.

[6] Fuel costs are 5€/GJ for gas.

At the given fuel costs the cost of electricity for the gas fired combined cycle with PCC are lower than for the ultra-supercritical pulverised coal fired power station with PCC. However, the CO_2-avoided costs for the ultra-supercritical pulverised coal fired power station are lower than for the gas fired combined cycle.

Conclusions

The study found that almost all FEED studies, pilot plants, demonstration plants and technical analysis' were based on 90% CO_2-capture regardless of the technology type, location and fuel type.

The literature assessment indicated that there are no technical barriers to increasing capture rates in the three capture routes and with the broad suite of CO_2-capture technologies. Where a capture technology is less suitable to achieve higher capture rates the combination with biomass co-combustion would be a simple alternative to reduce net CO_2-emissions to zero.

It was furthermore found that as CO_2-capture rates are increased the indirect emissions from fossil fuel use become dominant. Using literature data to estimate the indirect emissions for the chosen fuels it was found that this was a significant barrier for reducing overall emissions, particularly in gas fired power stations.

The techno-economic performance of the standard PCC process applied to a fossil fuel fired power plants demonstrated that the additional costs for achieving an essentially zero CO_2-emission fossil fuel fired power plant were quite modest in comparison with the costs needed to achieve 90% CO_2-capture in the first place. For coal fired power stations the option of using a combined biomass co-combustion (10% biomass) with a standard PCC process (90% CO_2 capture) was the lowest cost option.

Recommendations

The findings from this study provide the basis for the following recommendations:

- As the power sector has increasing access to generation options that have zero CO_2 emissions, more attention is needed on zero emission fossil fuel power plants using CCS in research and development. The demonstration of zero emission CCS technologies, rather than low emission technologies, is needed from an overall greenhouse gas emission reduction perspective to reduce concerns around residual CO_2 emissions.
- The immediate pathway towards zero emissions is the combination of CCS from power plants with biomass co-firing, and demonstration of such power plants should be pursued with vigour.
- The techno-economic optimisation of other CO_2 capture technologies, other than amine-based technologies for PCC as a function of the CO_2 capture rate, is needed to underpin the availability of a wider range of options. Chemical looping technologies are a good example, but also hybrid options such as membrane technologies (with lower CO_2 capture rates) in combination with biomass co-combustion deserve further assessment.

- The reduction of the indirect emissions associated with the use of coal and gas are of similar urgency and should also be pursued with vigour as part of the zero emission fossil fuel pathway.

1 Introduction

1.1 Study context

At the COP 21 meeting in December 2015 in Paris, 195 countries adopted the first-ever universal, legally binding global climate deal. The agreement sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to “well below 2°C” above pre-industrial levels. This target implies a carbon budget significantly more challenging than that required to meet a “2 ^{o}C” scenario which is already an appreciable target.

While nuclear power and renewable energy technologies have important roles, the continued use of fossil fuels to power the global economy makes CO_2-capture and storage (CCS) a key technology in a “well below 2°C scenario”. CCS has long been recognised by most leading scientific bodies as an essential technology to meet 2°C at least cost and becomes even more of an imperative as a more stringent climate objective is adopted.

In a “well below 2°C” scenario, it is projected that net zero carbon emissions would be required early in the second half of this century. In that case, the CO_2 capture rates would need to be high - much higher than most current design values. Capture technologies typically have capture rates reaching 85-90%, leaving 10-15% residual emissions. Given the continued use of fossil fuels, this level of capture falls short of what would be needed to remain within a “well below 2°C” carbon budget.

The recent Energy Technology Perspectives report (IEA 2017a) from the International Energy Agency indicated that “*under the below 2 degree scenario, efforts will need to focus on developing capture technologies that can more effectively and economically capture CO_2 from smaller and more dilute streams, and that have capture rates approaching 100% to avoid residual emissions from current technologies*”. This was confirmed in a recent study which considered a range of scenarios aiming to limit global mean temperature increase to less than 1.5 ^{o}C (Rogelj *et al.* 2018). The study was based on six Integrated Assessment Models (IAM) and five so-called shared socioeconomic pathways. Not all of the pathways were amenable to limiting the temperature increase to less than 1.5 ^{o}C. The study stated that residual CH_4 emissions from coal mining or gas handling, and CO_2 emissions due to imperfect capture and leakage became too substantial in the very stringent mitigation scenarios. This resulted in less deployment of CCS in fossil fuel operations. It is clear that the current capture rates used in the models could be a limiting factor in potential CCS deployment.

Furthermore, to achieve the low net CO_2 emissions anticipated, it is likely that the concept of negative emissions technologies would need to be put into practice. In theory, several technologies, such as afforestation, direct air capture and bioenergy with CCS have the potential to lower atmospheric CO_2 levels, but each of these has its own challenges. Consequently, following the Paris Agreement, the role of CCS and the incentive to substantially increase the capture rate rises - as does the need to deploy negative emissions technology.

In this study, we investigated the technological, economic, environmental and political barriers to moving towards zero CO_2 emissions from fossil fuel-based power generation plants equipped with CCS. Accordingly, the potential to improve CO_2 capture rates above the customary 85%-90% was explored across the full range of capture technologies. We also explored the potential use of biomass in combination with CCS (e.g. by co-combustion or co-gasification) to achieve net zero (or net negative) emissions, this will also be explored in the study. In practice, biomass could be deployed to achieve those aims instead of or in addition to raising capture rates.

Our study built on the results of a similar study the IEA GHG commissioned more than ten years ago (IEA GHG 2006). Capture technologies have progressed significantly since then and CCS technology has been deployed more widely. However, the focus of technology development over the past decade has been to improve energy efficiency and strive for cost reductions rather than improve capture rates.

There is an obvious advantage in favouring concepts that have lowest costs per tonne CO_2 emission reduction, regardless of the capture rate or amount of emission reduction, as this will be an important determinant in ranking the economic performance of low emission technologies. Against the background of the need to reach zero emissions from power generation, we have revisited the options presented in the IEAGHG report to achieve this goal. The IEAGHG report also contained technologies that have not seen further development or deployment leaving us scope to revisit the selection of technologies bearing in mind the current commercial scale and demonstration projects in the power sector. Lastly, the IEAGHG report also highlighted the necessity for a life cycle analysis of CCS technologies including indirect emissions.

1.2 Study overview

In this study, we first review the capture rates used in experimental and modelling practice, with the results in Section 2 incorporating a brief assessment of major capture routes. Outcomes from previous studies are summarised in Section 3. We explore the use of capture rates in integrated assessment models in Section 4, which highlights the need for better understanding of direct and indirect emissions from fossil-fuel-fired power plants, particularly with increasing capture rates that would reduce the impact of the power plant emissions. Our analysis in Section 5 also includes the impact of integrating renewable energy into a CO_2 capture system. Section 6 looks into biomass technologies as an option to reduce greenhouse gas emissions from power stations, followed by a discussion on CO_2 capture technologies in Section 7. In Section 8 we focus on the impact of increasing capture rates in amine-based post-combustion CO_2 capture, in view of its position as the leading technology in terms of deployment on power plants.

2 Capture rates in experimental and modelling practice

2.1 Determinants for CO_2 capture

CO_2-separation process have been used in the natural gas industry for decades, where the capture rate has been a consequence of the product gas specification. For pipeline transport, the CO_2-content of the product gas typically needs to be lower than 2% (volume), or lower than 50 ppm (volume) in case of liquefaction, and this will determine the amount of CO_2 captured and capture rate. The introduction of CO_2 capture and storage (CCS) as a low-emissions technology will most likely build on the existing and commercially available technologies and apply them in a new environment.

The capture process needs to deliver a CO_2 product that can be transported (e.g. pipeline, ship) and meets the requirements for storage in the underground. While CO_2-quality requirements will vary across different jurisdictions and storage options (e.g. geological storage versus enhanced oil recovery) many studies and researchers have utilised a 95% CO_2 purity as the benchmark.

The choice of a certain capture rate in CCS-chains is largely determined by the aim to optimise the degree of CO_2 capture in a techno-economic sense. This incorporates a full techno-economic analysis of the overall integrated process in which, for example, a CO_2 price or revenue from the sale of CO_2 can also be factored in. A significant impact can therefore be expected from the type of capture route (i.e. post-/pre-combustion or oxyfuel) and separation processes used (e.g. absorption, adsorption, membranes, cryogenics). Fuel costs can also influence the determination of capture rate. A combination of options might therefore be preferred as a result of the optimisation process.

Regulation or prescription of a power plant CO_2 emission intensity might also be a determining factor for capture rates. For instance, in some jurisdictions, proposals have been put forward for coal-fired power stations to have CO_2 emissions no higher than an unabated gas-fired combined cycle. This would mean approximately 60% would have to be captured from coal-fired power stations to meet that requirement. One must distinguish between the capture rate for a power plant facility, which might consist of different units, and the capture rate from a particular gas stream. This study will focus on the latter case.

From an environmental perspective, one would want to maximise the amount of CO_2 capture from power stations, because alternative power generation processes based on renewable or nuclear technology have CO_2 emissions that are close to zero. Table 1 provides a coarse classification of power generation technologies as determined by the emission levels based on the typical capture rate of 85-90%. CCS for power stations has higher emission levels than renewable energy or nuclear energy based power stations, and can therefore be classified as low emission, but not zero emission.

Table 1 Emission classification of power generation technologies

Emission Classification	Specific CO_2 emission range [kg/kWh]	Example technology
High	> 0.7	Coal-fired power station
Medium	0.3 – 0.7	Gas-fired combined cycle
Low	0.05 – 0.3	Coal and gas-fired power stations with CCS (90% CO_2 capture)
Zero	0 – 0.05	Wind turbines, solar thermal, photo-voltaic cells, nuclear
Negative	< 0	Bioenergy with CCS

2.1.1 Post-combustion CO_2 capture

Post-combustion capture (PCC) processes involve removing CO_2 from flue gas streams downstream of the combustion process (Figure 1). This involves separating CO_2 (typically 3-15 vol%, dependent on fuel type) from an atmospheric pressure gas stream consisting mainly of N_2. Depending on the fuel type, other trace contaminants can include H_2O, O_2, SO_x, and NO_x. As PCC processes are applied downstream of the fuel conversion step, they can be applied similarly to all fuel types (oil, coal, gas, biomass).

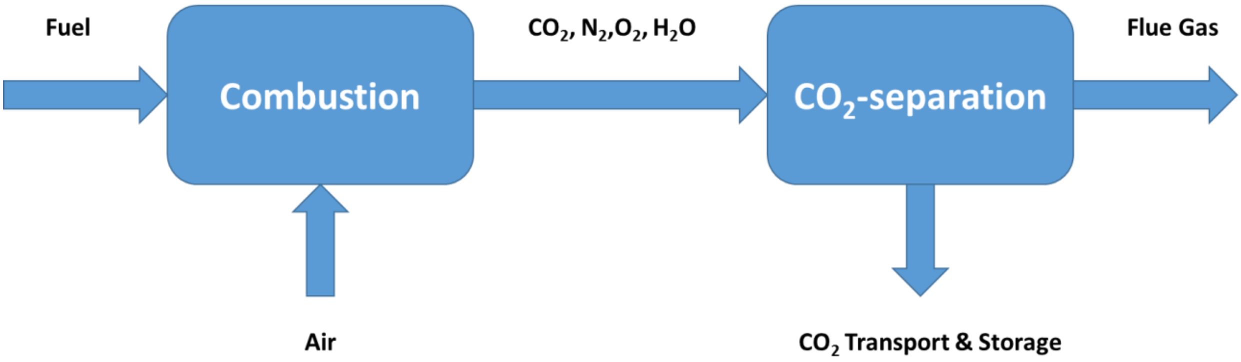


Figure 1 Post-combustion CO_2 capture

Increasing the capture rates in PCC requires the separation of CO_2 at significantly lower concentration levels, where driving forces for CO_2-separation will be significantly reduced. This is anticipated to result in increased capital costs and higher energy costs. For a given fuel, capture rates can only be influenced through modifications of the CO_2-separation process.

2.1.2 Pre-combustion CO_2 capture

In pre-combustion capture, the CO_2 is removed prior to combustion of the fuel gas (Figure 2). This includes removing CO_2 from the syngas stream. Syngas (a mixture of predominantly CO_2, CO, H_2 and H_2O) can be generated through steam methane reforming, or gasification of solid and liquid fuels (e.g. integrated-gasification combined cycles, IGCC). CO_2 partial pressures in pre-combustion capture will be much higher than in PCC processes. For IGCC, gas pressures can be in the range 25-70 bar, with CO_2 concentrations between 30-45 mol% (15-25 mol% if natural gas is primary energy source) after water-gas shift and water removal.

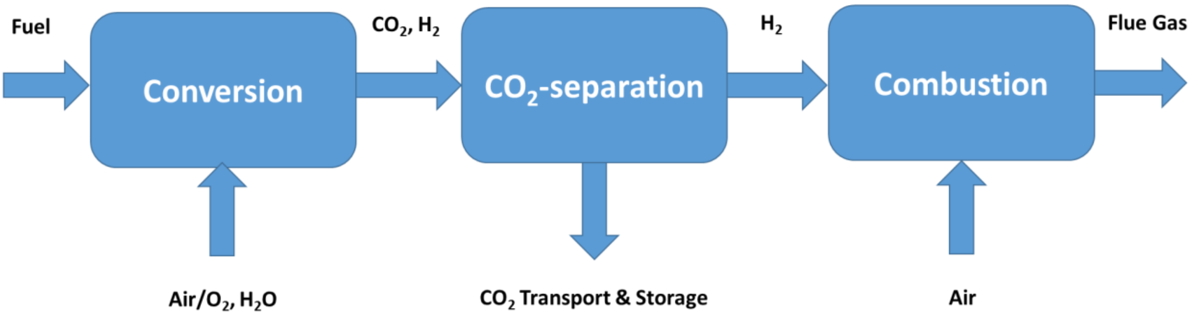


Figure 2 Pre-combustion CO_2 capture

The capture rate is not only determined by the CO_2-separation process rate, but also the fuel-conversion process that will ultimately produce a CO_2/H_2 stream. In particular, the shift reaction that converts CO in the fuel gas mixture from the steam reforming or gasification into CO_2 will need to achieve high conversion rates to limit the slip of CO with the hydrogen product. Hence, an increase in the capture rate will need to consider both steps. Ultimately one may also consider CO_2 capture from the flue gas as a way to reduce CO_2 slip.

2.1.3 Oxyfuel systems

Oxyfuel combustion processes (also called oxy-combustion) involve combusting the fuel in nearly pure O_2 to produce a flue gas stream concentrated in CO_2 (Figure 3). Some of the product CO_2 is recycled to the combustion chamber to maintain temperatures. The main contaminant in the CO_2 stream is water vapour which is easily removed after the combustion process when the CO_2 stream is typically cooled to remove the bulk of the water vapour. The required purity of the CO_2 then determines the downstream treatment steps applied.

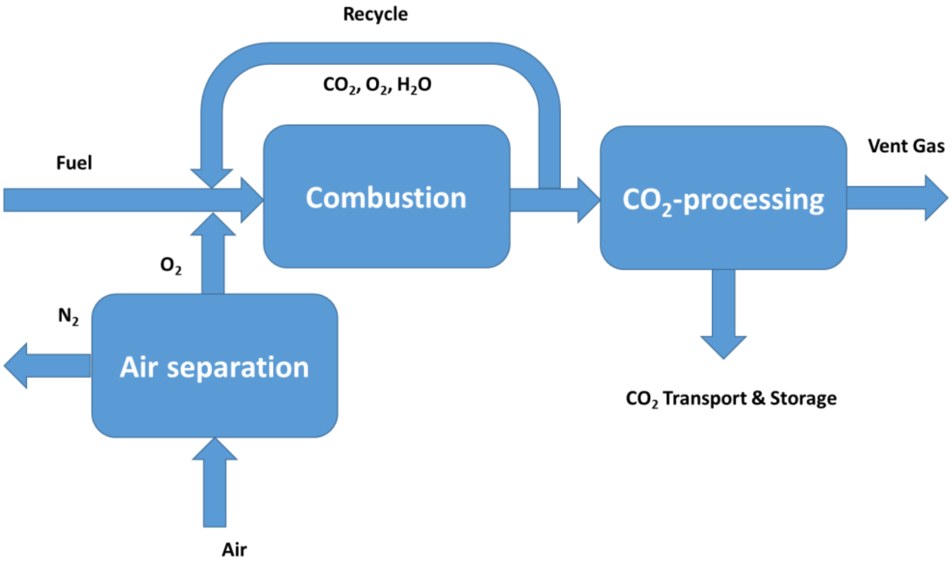


Figure 3 Oxyfuel process

For oxy-combustion, theoretically nearly 100% capture of CO_2 could be achievable if the whole flue gas stream, including any remaining impurities, was compressed for transport and storage. In practice O_2 will be present in the CO_2 product, since it is used in excess, as will contaminants normally resulting from a combustion process, such as sulphur and nitrogen oxides. The oxygen used in the process might also contain inerts such as argon and residual nitrogen that need to be vented together with CO_2 to avoid accumulation in the process. Another source of impurities is the air ingress, as boilers are normally operated at a pressure slightly lower than atmospheric.

Higher capture rates can be achieved by removing CO_2 from any vent streams in the process. Treatment of vent gases might be needed in any case, as they contain higher concentrations of sulphur and nitrogen oxides and might contain mercury, for which emission limits will apply.

2.1.4 Overview of capture rate determinants in capture routes

Table 2 summarises the factors that determine the capture rates for the three routes (oxyfuel, pre-combustion and post-combustion), including the opportunities to reduce CO_2 slip. The capture rates for both oxyfuel and pre-combustion CO_2 capture are determined by more than one part of the process. This indicates there could be more flexibility in achieving a higher capture rate but also it has the inherent drawback that all issues need to be addressed to reduce CO_2 slip and increase CO_2 capture rates. In that respect the capture rate in a PCC route can only be impacted by the CO_2-separation process, which is less flexible but conceptually a simpler approach.

The variety of measures to reduce CO_2-slip provide significant confidence that it is possible to increase capture rates in all three routes. However, these measures are likely to involve additional equipment, resulting in increased capital costs and operational costs. This might be a barrier to the use of higher capture rates.

Table 2 Summary of capture rate determinants and opportunities to lower CO_2 slip

Capture route	Capture rate determinant	Opportunity to lower CO_2 slip
Oxyfuel	O_2 purity Ambient air leakage CO_2-processing unit	CO_2-recovery from vent gases Avoidance of inerts in CO_2 product Fuels that do not produce gaseous inerts through combustion Trade-off with CO_2 purity
Pre-combustion	Carbon conversion process CO_2 capture process O_2 purity (gasification)	Water gas shift reaction conditions Avoidance of inerts in syngas Fuel that do not produce gaseous inerts through reforming or gasification Residual CO recovery from syngas CO_2 separation from syngas CO_2 separation from flue gas
Post-combustion	CO_2 capture process	CO_2 separation from flue gas

2.2 Capture rates used in practice and in studies for large scale plants

Currently, two operational CO_2 capture plants are applied at power-plant scale. Both plants operate on coal-fired power plants, utilise amine-based PCC technology and achieve capture rates around or above 90% as indicated in Table 3.

Table 3 Operational integrated power plants with CO_2 capture

Project	Operational	Capacity	Capture technology	Capture rate	Use
Boundary Dam power plant (Unit 3), Estevan, Saskatchewan, Canada	2014	1 Mtpa*	Amine based Post-combustion (Shell CANSOLV)	~ 90%	Enhanced oil recovery, also supply for geological storage in aquifers
W.A. Parish power plant (Unit 8), Thompsons, Texas, USA	2017	1.4 Mtpa*	Amine based Post-combustion (MHI)	> 90%	Enhanced oil recovery

* Mtpa=Million tonnes per annum.

Several front end engineering and design (FEED) studies have been carried out for a variety of CCS project initiatives, focused on power plants. Table 4 provides an overview of those projects for which FEED studies were published and data on the capture rate could be found. It also includes other projects in an advanced state of development. Capture rates around 90% were the target for the three capture options, post-combustion, pre-combustion and oxyfuel.

Table 4 Overview of FEED studies and other advanced project initiatives

Study	Capacity	Capture technology	Capture rate	Use
Longannet, Scotland; Coal-fired power plant	~ 2 Mtpa (8000 hours/annum assumed)	Amine based post-combustion (Aker Clean Carbon)	> 90 %	Offshore geological storage
Kingsnorth Carbon Dioxide Capture and Storage Demonstration Project, England; Coal-fired power plant	~ 2.2 Mtpa (8000 hours/annum assumed)	Amine based post-combustion (MHI)	90 %	Offshore geological storage
ROAD project, Rotterdam, Netherlands; Coal-fired power plant	1.4 Mtpa	Amine based post-combustion (Fluor)	90 %	Offshore geological storage
American Electric Power Mountaineer CCS II Project, West Virginia, USA; Coal-fired power plant	1.5 Mtpa	Chilled ammonia based post-combustion (Alstom, now GE)	> 90 %	Onshore geological storage
Project Pioneer, Keephills, Alberta, Canada; Coal-fired power plant	1 Mtpa	Amine based post-combustion (MHI)	90 %	Onshore geological storage and enhanced oil recovery
Peterhead CCS project, Aberdeenshire,	~ 1 Mtpa	Amine based post-combustion (Shell CANSOLV)	90 %	Offshore geological storage

Scotland; Gas-fired combined cycle				
Getica CCS demo project, Turceni, Romania; Coal-fired power plant	~ 1.9 Mtpa (8000 hours/annum assumed)	Chilled ammonia based post-combustion (Alstom, now GE)	> 85 %	Onshore geological storage
Tenaska Trailblazer project, Texas, USA; Coal-fired power plant	5.5 Mtpa (8000 hours/annum assumed)	Amine based post-combustion (Fluor)	> 90 %	Enhanced oil recovery
Compostilla OXYCFB300 Project, Leon, Spain; Coal-fired power plant	~ 2 Mtpa (8000 hours/annum assumed)	Oxyfuel (Foster Wheeler)	91 %	Onshore geological storage
White Rose, Selby, Yorkshire, England; Coal-fired power plant	2 Mtpa	Oxyfuel (General Electric)	90 %	Offshore geological storage with option for enhanced oil recovery
Texas Clean Energy Project, Odessa, Texas, USA; Coal-fired power plant	3 Mtpa	Pre-combustion	90 %	Enhanced oil recovery
Futuregen 2.0, Meredosia, Illinois, USA; Coal-fired power plant	~ 1 Mtpa	Oxyfuel (Babcock & Wilcox)	90 %	Onshore geological storage
Futuregen original, Mattoon, Illinois, USA; Coal-fired power plant	1 Mtpa	Pre-combustion	90%	Onshore geological storage
Vattenfall, Jänschwalde, Germany, Lignite fired power plant	~ 1.5 Mtpa	Oxyfuel	90-93%	Onshore geological storage
Don Valley Power plant, Yorkshire, England	1.5 Mtpa	Post-combustion (pressurised flue gas from gas firing – Sargas)	90%	Offshore geological storage

The capture rates seen in the large scale plants and FEED studies correlate well with those used in detailed costing studies as summarised in Rubin *et al.* (2015), i.e. for coal-fired power stations, capture rates used in post- and pre-combustion processes and for natural gas-fired combined cycles equipped with post-combustion capture rates were equivalent to 90%. For oxyfuel systems applied to coal-fired power stations, 90% was also the norm with only one study using a relatively high value of 98%.

3 Overview of previous work

Bozzuto et al. (2001) investigated the addition of CO_2 capture to an existing coal-fired power plant. CO_2 capture was via absorption into 20 wt% monoethanolamine (MEA). For capture fractions below 90%, they determined that MEA-based absorption was a better alternative to oxy-combustion. They adjusted operating parameters to increase CO_2 recovery until a significant increase in plant size and/or energy was observed, which occurred above CO_2-capture efficiencies of 95%. They also evaluated a novel CO_2 capture concept using upstream catalytic removal of O_2, followed by CO_2 capture via a MEA/MDEA (N-methyl diethanolamine) blend. In this case, adjusting operating parameters were noted to cause an increase in energy/plant costs for CO_2 capture efficiencies above 91%. No explanation is provided for the observed increases.

The IEA Greenhouse Gas R&D Programme (IEAGHG) commissioned a first study on the topic of “zero emissions power stations” in 2006, which was carried out by the Energy Research Centre of the Netherlands (IEA GHG 2006). It provided a longlist of 20 CO_2-capture processes across the three options of post-, pre-combustion and oxyfuel with 85% being the typical CO_2 capture rate. Further analysis and screening eliminated some overlap in these processes, and resulted in 10 shortlisted processes. However, in terms of their effectiveness to achieve zero emissions, no clear front runner could be identified. The study focused further on a comparison of the three options in terms of cost per unit electricity produced and cost per tonne CO_2 emission reduced. The analysis was based on a short-cut method that relied on the definition of a base case derived from the literature for each of the three process routes, and the comparison was made within each process route. The effect of increasing capture rate was subsequently estimated by considering the split in investment costs and operating cost for a predefined base case, and the resulting changes in this with increased capture rate using suitable scaling factors.

The results in Table 5 indicate that the impact of increased capture rates for oxyfuel in a coal-fired power plant were minor in terms of electricity costs and efficiency, and only derived from the removal of CO_2 from vent gases. The study pointed out that if the product CO_2-stream can be stored with the remaining impurities and inerts, oxyfuel will be a zero emissions option without any impact on electricity cost or power plant efficiency. This was already achieved for oxyfuel using gas.

For the pre-combustion process route the capture rate could be increased to 98% by the use of a multi-stage, optimised shift reaction (increased carbon conversion) followed by a high performance physical absorption process (increased CO_2 separation). The electricity cost increased a maximum of 18%, in the case of coal.

Cost increases were much higher for the PCC process: increasing capture from 85% to 99% increased electricity costs by 45% for coal and 30% for gas. This resulted from the combined effect of increased investment costs (taller absorber and desorber columns, larger heat exchangers through higher flow rates) and increased operational costs (higher energy requirements for regeneration of absorption liquids). There was a significantly larger effect on the power plant efficiency for post-combustion capture where increasing the capture rate from 85% to 99% (coal) and 98% (gas) resulted in a 20% efficiency drop compared with only 10% for pre-combustion capture, and at most 1% in the case of oxyfuel.

Overall for all cases with higher capture rates, the efficiency was highest for the pre-combustion CO_2 capture route.

Table 5 Impact of increased capture rate on efficiency and normalised electricity cost for the three capture process routes (IEA GHG 2006) for coal and gas-fired power plants

Process route	Coal		Gas	
Post-combustion	Capture rate base 85%	Capture rate enhanced 99%	Capture rate base 85%	Capture rate enhanced 98%
	Efficiency 33%	Efficiency 26%	Efficiency 47%	Efficiency 40%
	Electricity cost 100	Electricity cost 145	Electricity cost 100	Electricity cost 130
Pre-combustion	Capture rate base 85%	Capture rate enhanced 98%	Capture rate base 88%	Capture rate enhanced 99%
	Efficiency 39%	Efficiency 36%	Efficiency 47%	Efficiency 45%
	Electricity cost 100	Electricity cost 118	Electricity cost 100	Electricity cost 111
Oxyfuel	Capture rate base 90.8%	Capture rate enhanced 99%	Capture rate base 98%	Capture rate enhanced 99%
	Efficiency 35.4%	Efficiency 34.5%	Efficiency 45%	Efficiency 45%
	Electricity cost 100	Electricity cost 103.8	Electricity cost 100	Electricity cost 100

The study also presented the overall impact of the capture rate on CO_2 abatement costs (Figure 4). The results indicated a sharp increase in the costs per tonne CO_2 emission reduced for the PCC cases when the CO_2 capture rate increased above 95%. The emission reduction costs per tonne CO_2 for oxyfuel were actually somewhat reduced as it was considered that any impurities could be stored with the CO_2 product. For pre-combustion coal plants a maximum capture rate of 98% was achievable.

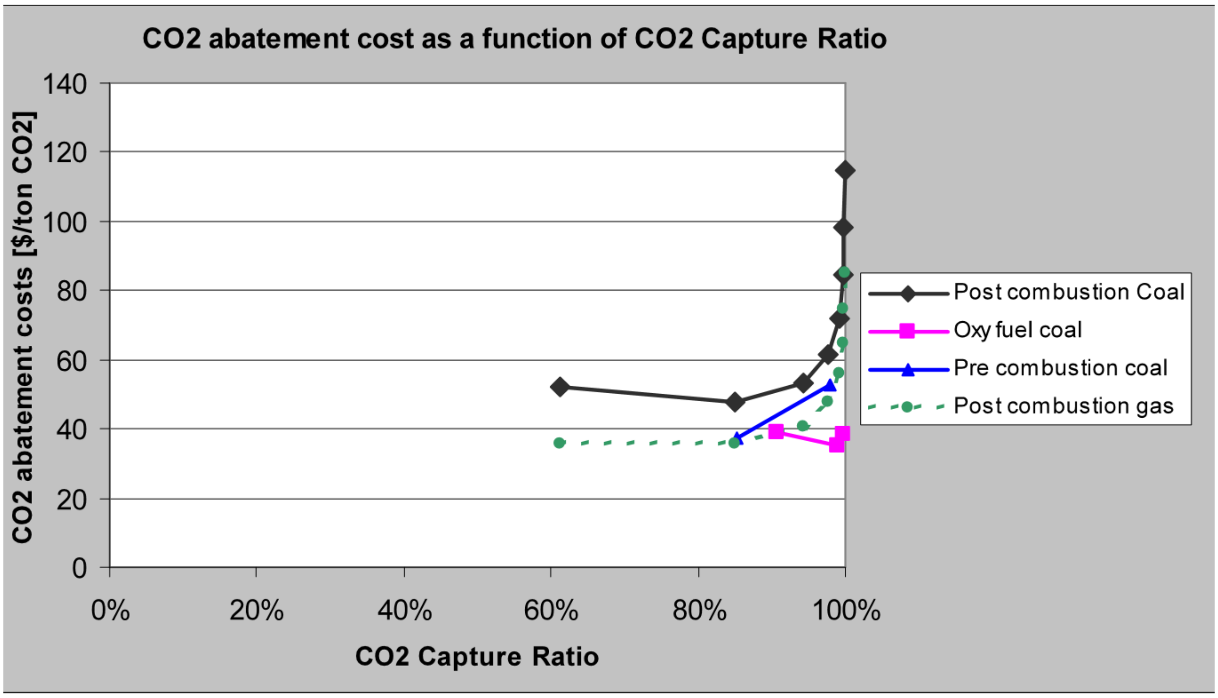


Figure 4 Cost per tonne CO_2 emissions reduced as a function of CO_2 capture ratio (IEAGHG 2006)

Abu-Zahra et al. (Abu-Zahra *et al.* 2007a; Abu-Zahra *et al.* 2007b) also considered the impact of capture rate on process performance of an amine based PCC process by carrying out a full techno-economic analysis at different levels of CO_2 capture for a coal-fired power plant. The analysis was based on treatment of the complete flue gas stream. The increase in capture rates resulted in a relatively minor increased optimal thermal energy requirement (reboiler duty) as shown in Figure 5. The impact on the cost per tonne CO_2 emission reduction was quite small for the 30% MEA solution considered with only a small variation for capture rates between 70 and 99% (Figure 6).

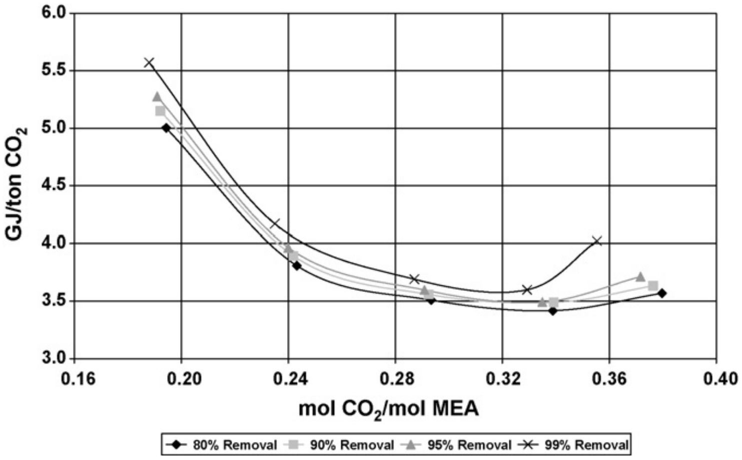


Figure 5 Thermal energy requirement as a function of lean loading at different CO_2 capture rates (Abu-Zahra *et al.* 2007a)

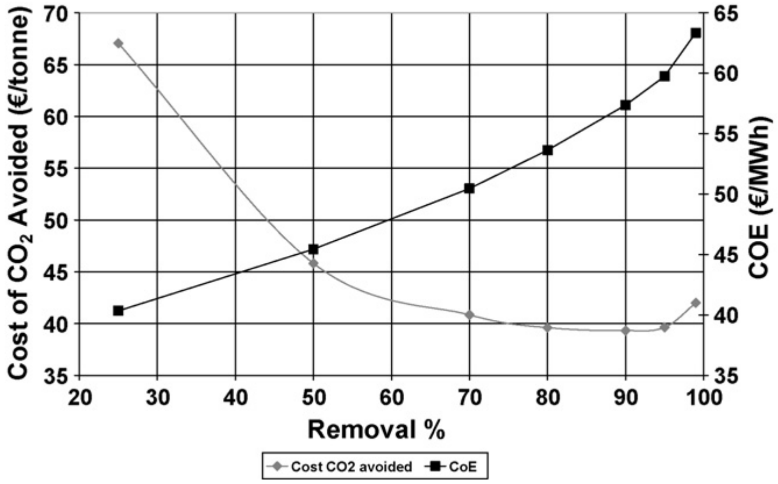


Figure 6 Cost per tonne CO_2 emission reduction and cost of electricity at different CO_2 capture rates (Abu-Zahra *et al.* 2007b)

In a different modelling analysis, also carried out for a 30% MEA solution and a coal-fired power station, Flø *et al.* found a significant increase in the reboiler duty as the capture rate was increased to values above 98%, leading them to conclude that the techno-economic optimum was close to 98% (Figure 7) (Flø *et al.* 2016).

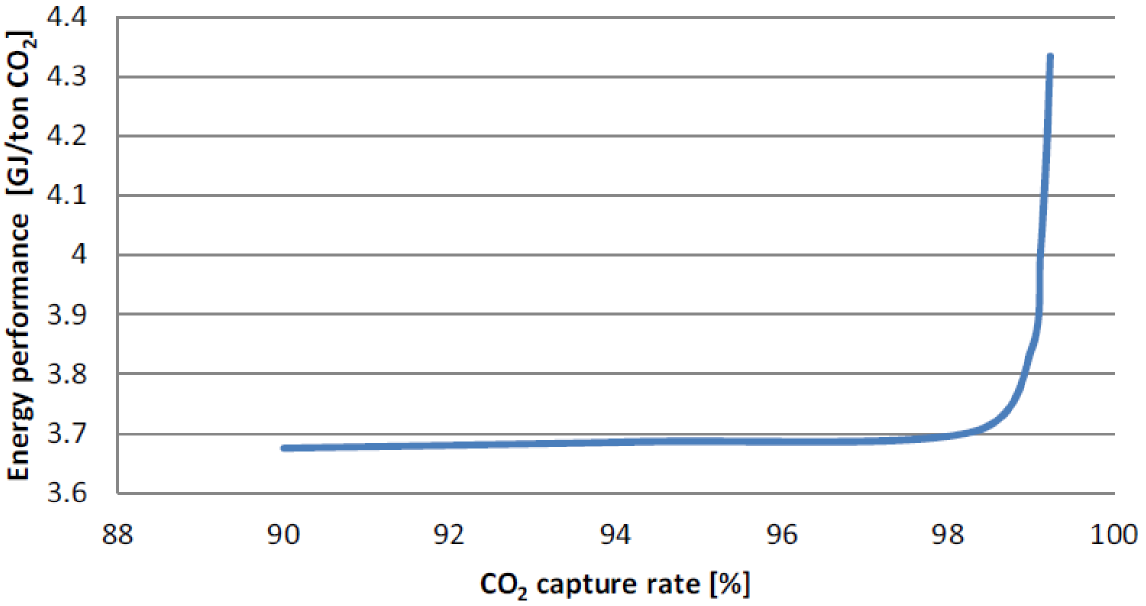


Figure 7 Reboiler duty as a function of CO_2 capture rate for 30% MEA (Flø et al. 2016)

Variations of the CO_2 capture rate were also investigated in a study commissioned by the US Department of Energy – National Energy Technology Laboratory for a supercritical coal-fired power station and an integrated gasification combined cycle both incorporating CO_2 capture (NETL 2013). The post-combustion capture process modelled represented the Econamine FG Plus^{SM} process. For capture rates above 70% the whole flue gas stream was treated; at lower rates, 90% capture was modelled from a slip stream, i.e. part of the flue gas simply by-passed the CO_2 capture unit. The variation in the costs per tonne CO_2 emission reduction was limited over the range 70-99% as can be seen from Figure 8. This is consistent with the results from Abu-Zahra *et al.* (2007b) and it seems that capture rates in a post-combustion capture process can be increased to 99% with only a limited penalty (~5%) on the cost per tonne CO_2 emission reduced. This seems at odds with the assessment of the IEAGHG study (see Table 5).

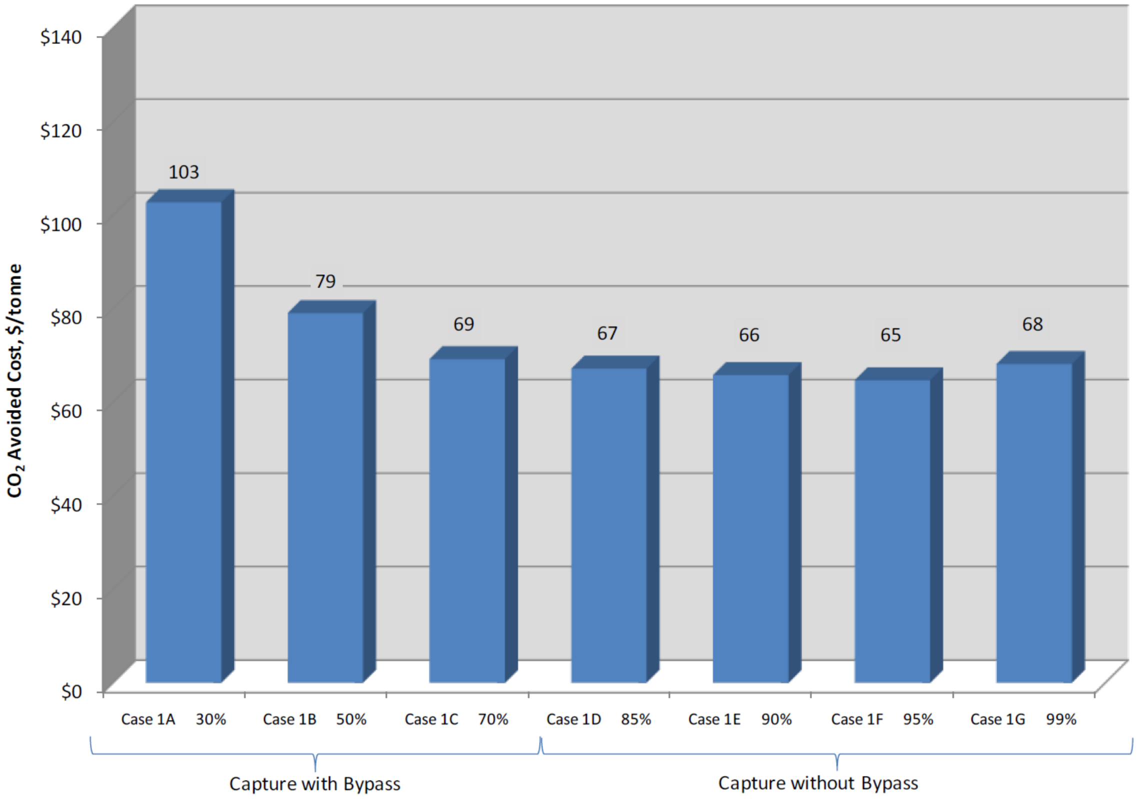


Figure 8 Cost per tonne CO_2 emission reduction at different CO_2 capture rates for a supercritical power station equipped with amine-based post-combustion CO_2 capture (NETL 2013)

For the IGCC analysis a range of options was investigated that resulted in a variation of the CO_2 capture rate between 25% and 97%. The lowest rate was achieved for CO_2 capture from the unshifted syngas, and the highest rate through a 2-stage water-gas-shift reactor with a double stage physical absorption process using Selexol^{TM}. Intermediate capture rates were obtained by selecting the by-pass ratio of the water-gas-shift reactor and changing from a one stage to a two stage water gas shift. An overview of the costs per tonne CO_2 emission reduction is provided in Figure 9 with the IGCC or the supercritical power station as reference. As a result of the higher CO_2-content in the fuel gas, the costs for CO_2 capture relative to the IGCC itself are quite low. When compared with the supercritical power station, the costs per tonne CO_2 emission reduction were similar at capture rates above 85%. The IGCC had higher efficiency than the supercritical plant in all cases, but higher cost of electricity, except at capture rates above 85% where the cost of electricity was quite similar.

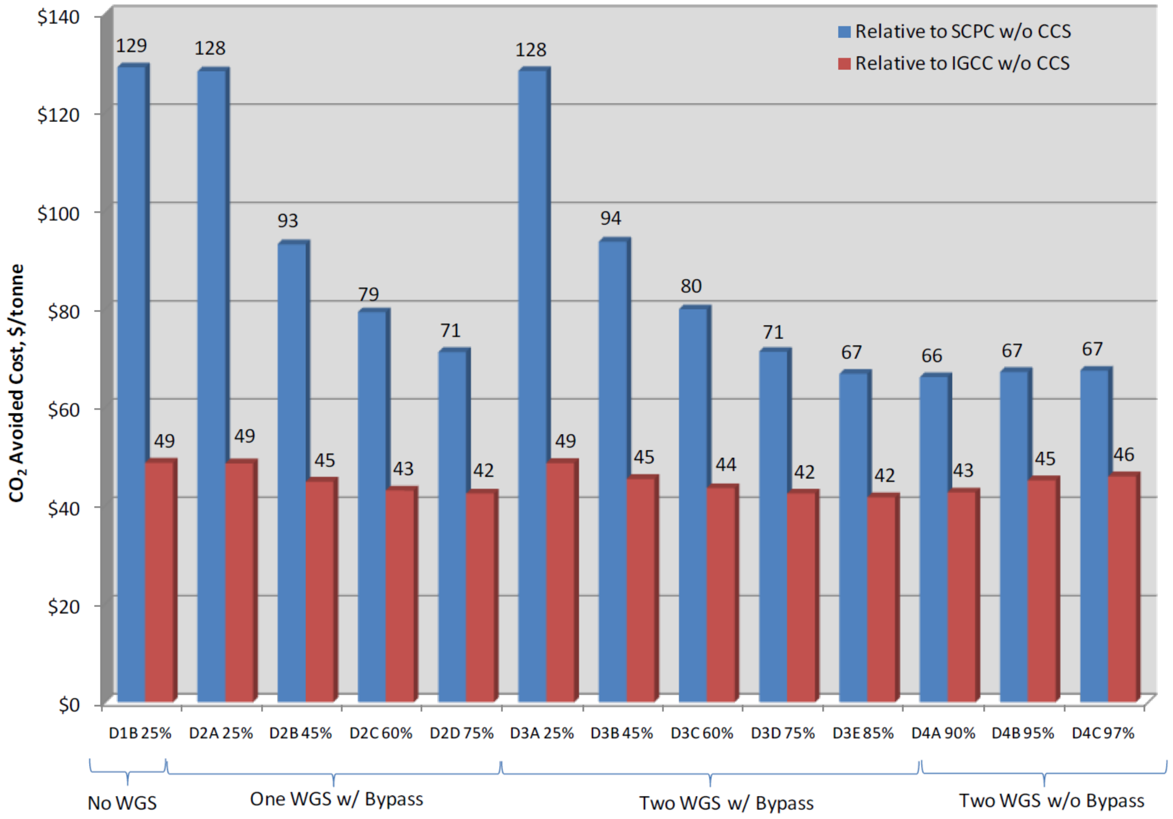


Figure 9 Cost per tonne CO_2 emission reduction at different CO_2 capture rates for an integrated gasification combined cycle with one/two stage water gas shift and physical absorption based CO_2 capture (NETL 2013)

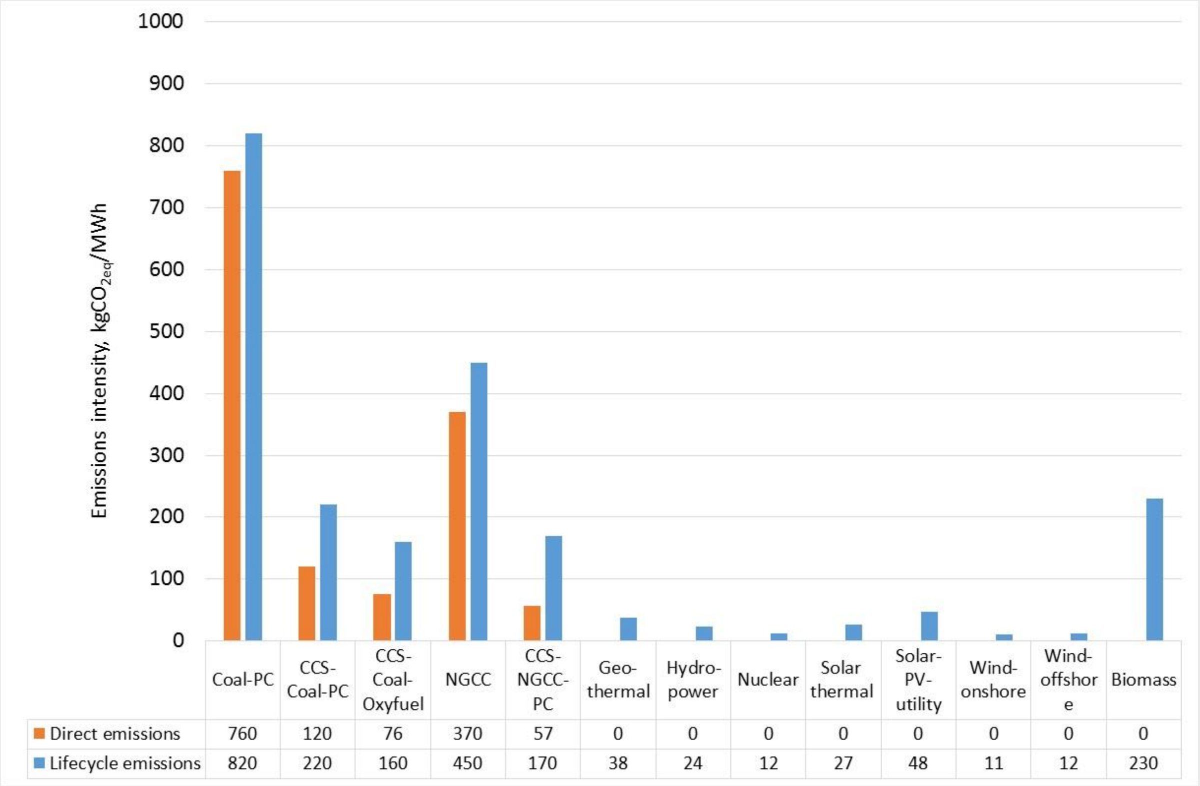
4 CO_2 capture and storage in integrated assessment models

Integrated assessment models describing the interplay of economic activity, the energy system and climate change issues rely on high-level assumptions of the techno-economics and societal aspects of technologies for the production, transport, conversion and use of energy. These assumptions are exclusively derived from techno-economic studies for the individual technologies and ensuing research efforts to consolidate these results. In terms of the role that CO_2 capture and storage (CCS) plays in these models, it is important to assess the performance information that is being used in the integrated assessment modelling efforts. This involves identifying the range of values utilised for CO_2 emission intensity (kg CO_2/MWh_e) and specific fossil-fuel use (often expressed as the heat rate) as well as the fuel price and cost of electricity (\$/MWh_e) for the technologies with and without CCS. It also requires determining the performance data used for including biomass energy conversion systems into the modelling scenarios.

The CO_2 emission intensity of a fossil-fuel-fired power station, as for any energy conversion process, can be derived from a life cycle assessment. It will consist of the following contributions (IPCC 2014a):

- Direct emissions, which in the context of a power plant refer to greenhouse gas emissions as a result of the on-site power production. These emissions are determined by the carbon content of the fuel and the energy conversion efficiency. Renewable energy conversion systems, such as wind turbines and photo-voltaic cells, have zero direct emissions.
- Indirect emissions, which in the context of a power plant refer to a variety of emissions such as those occurring during the extraction and transport of fossil fuels (mostly methane) or embodied in the infrastructure used. These are the only emissions for renewable energy conversion systems.

Summing direct and indirect emissions provides the lifecycle emission for a particular energy technology. An overview of the lifecycle emissions and direct emissions of several energy technologies is given in Figure 10.



	Coal-PC	CCS-Coal-PC	CCS-Coal-Oxyfuel	NGCC	CCS-NGCC-PC	Geo-thermal	Hydro-power	Nuclear	Solar thermal	Solar-PV-utility	Wind-onshore	Wind-offshore	Biomass
🟧 Direct emissions	760	120	76	370	57	0	0	0	0	0	0	0	0
🟦 Lifecycle emissions	820	220	160	450	170	38	24	12	27	48	11	12	230

Figure 10 Direct and lifecycle emission intensity for a range of energy supply technologies (median values) (IPCC 2014a)

Fossil-fuel-based energy supply technologies have significant direct emissions, even after implementing CO_2 capture technologies. Non-fossil-fuel-based energy supply technologies have no direct emissions of greenhouse gases, but do have non-negligible indirect emissions. With the exception of biomass, the lifecycle emissions for these technologies are still one order of magnitude lower than the fossil-fuel-based energy supply technologies with CO_2 capture.

Integrated assessment models utilise data on energy supply technologies in different ways but always need to take into account the lifecycle emissions – either in their totality or as part of submodels used. Data on techno-economic performance parameters is also used. The input information is often based on a dedicated assessment of a range of literature data. An example is provided here for the Integrated Model to Assess the Global Environment (IMAGE) suite of models.

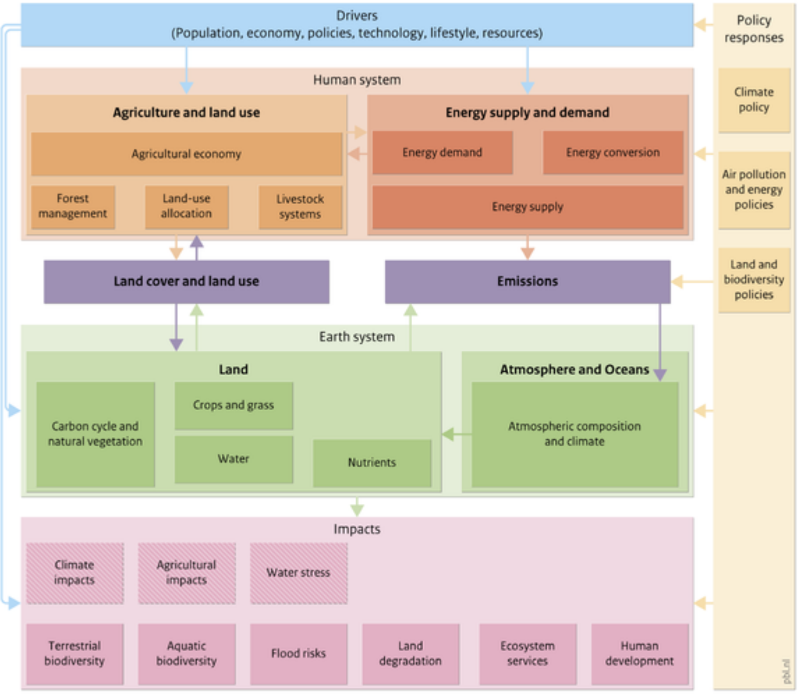
IMAGE is a dynamic integrated assessment framework used to analyse global change (Stehfest *et al.* 2014). It addresses a set of global environmental issues and sustainability challenges, the most prominent of which are climate change, land-use change, biodiversity loss, modified nutrient cycles, and water scarcity. The model framework is suited to large scale (mostly global) and long-term (up to the year 2100) assessments of interactions between human development and the natural environment, and integrates a range of sectors, ecosystems and indicators. The impacts of human activities on the natural systems and natural resources are assessed to see how such impacts hamper the provision of ecosystem services to sustain human development. The latest version, the IMAGE 3.0 model, has a wide range of outputs, including:

- energy use, conversion and supply;
- agricultural production, land cover and land use;
- nutrient cycles in natural and agricultural systems;

- emissions to air and surface water;
- carbon stocks in biomass pools, soils, atmosphere and oceans;
- atmospheric emissions of greenhouse gases and air pollutants;
- concentration of greenhouse gases in the atmosphere and radiative forcing;
- changes in temperature and precipitation;
- sea level rise;
- water use for irrigation.

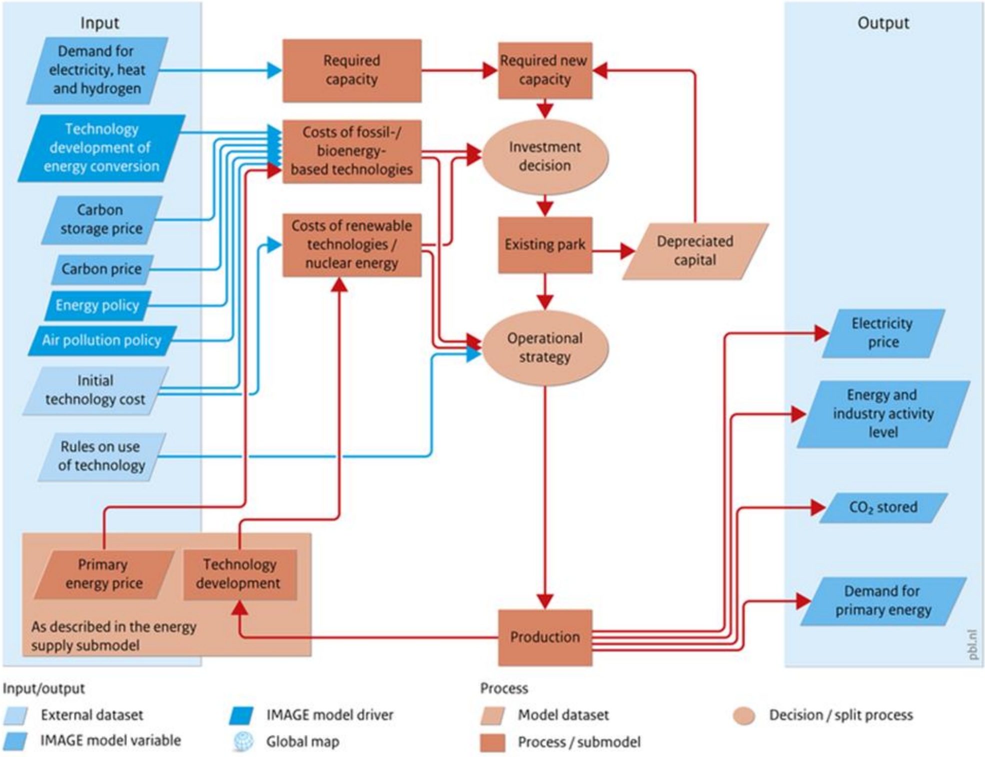
An overview schematic of IMAGE 3.0 is provided in Figure 11. Within IMAGE The IMage Energy Regional (TIMER) model has been developed to explore scenarios for the energy system in the broader context of the IMAGE global environmental assessment framework. TIMER describes 12 primary energy carriers in 26 world regions and is used to analyse long term trends in energy demand and supply in the context of the sustainable development challenges.

IMAGE 3.0 framework



Source: PBL 2014

TIMER model, electricity module



Source: PBL 2014

Figure 11 Overview schematic for the Integrated Model to Assess the Global Environment (IMAGE) 3.0 model (top) incorporating the electricity module of The Image Energy Regional (TIMER) model (bottom)

The TIMER model simulates long-term trends in energy use, issues related to depletion, energy-related greenhouse gas and other air-polluting emissions, and land-use demand for energy crops. The focus is on dynamic relationships in the energy system, such as inertia and learning-by-doing in capital stocks, depletion of the resource base and trade between regions. Performance and cost data are embedded within the TIMER energy conversion module with the data derived from Hendriks (Hendriks *et al.* 2004). Table 6 summarises the data for power plants, with the CO_2 capture rate estimated from the data to be in the range of 87-89% for all power plant types.

Table 6 Summary of characteristics for power plants with capture of carbon dioxide within The Image Energy Regional (TIMER) energy module

Fuel/plant type	Natural gas/natural gas-fired combined cycle (NGCC)	Coal/integrated gasification combined cycle (IGCC)	Natural gas/NGCC	Natural gas/steam cycle	Pulverised Coal/pulverised coal
Without capture					
Plant efficiency [% LHV]	58.0	47.0	58.0	42.0	42.0
Emission intensity [kg CO_2/kWh]	0.35	0.72	0.35	0.48	0.81
With capture	Pre-combustion	Pre-combustion	Post-combustion	Post-combustion	Post-combustion
Plant efficiency [% LHV]	51.5	42.2	52.0	36.4	33.7
Emission intensity [kg CO_2/kWh]	0.05	0.09	0.05	0.07	0.12
CO_2 avoided [%]	85	88	85	85	85
CO_2 captured [%]	87	89	87	87	88

More recently, the Intergovernmental Panel on Climate Change (IPCC) in their fifth assessment report (IPCC 2014a) based their analysis on a number of sources and provide ranges for direct emission intensities, efficiency and emissions related to infrastructure and fuel supply. Table 7 provides an extract for the power plant cases with CCS and their reference plants. The data do not provide exact capture rate data, but it stated that they are in the range of 90%. Compared with the data provided in Table 6, the coal oxyfuel option has been introduced and the pre-combustion gas option was not taken into account. For coal-fired power plants the oxyfuel coal option has the lowest direct emissions, whereas the IGCC option with CO_2 capture has the highest efficiency, but much lower than indicated in Table 6. The reasons for this are unclear, and resolving them will require a detailed investigation of the underlying references. It might explain the low level of commercial success of IGCC technologies as the efficiency difference with other technologies when CO_2 capture is deployed is small.

Table 7 Ranges of power station direct emissions and efficiency for a range of technologies used in IPCC 2014a

Technology	Direct emissions [$kgCO_2eq/MWh$]			Efficiency [% based on Lower Heating Value]		
	Min	Average	Max	Max	Average	Min
Pulverised coal	673	744	868	47.6	43.0	36.9
Pulverised coal + PCC	95	121	138	32.0	29.4	27.0
IGCC	713	734	762	44.9	43.6	42.0
IGCC With CO_2 capture	102	124	148	34.0	32.3	27.0
Coal – Oxyfuel	14	96	110	35.0	30.2	27.0
NGCC	349	370	493	59.0	55.6	41.7
NGCC + PCC	30	47	98	49.0	47.4	35

The IPCC (IPCC 2014a) provided an overview of results from a range of integrated assessment models with a multitude of scenarios for global futures in which the CO_{2eq} broadly ranged from 450 to 1000 ppm by 2100. While the uncertainty is significant, the lower concentration level (430–480 ppm) coarsely represented a range of scenarios with a more than 66% likelihood of global temperature increase of below 2°C. The high concentration level (720–1000 ppm) represented a range of scenarios with a more than 66% likelihood of global temperature increase staying below 4°C. For the inclusion and analysis of CCS most of these assessments assume that 90% of the CO_2 in the flue gas is captured, while the remaining emissions are mainly connected to the fuel chain.

Koelbl *et al.* (2014) provided results from a cross-model comparison of the use of CCS in twelve integrated assessment models. It appeared that a simple add-on cost for CCS was used in four models, with four models differentiating between CO_2 capture and storage and four models considering the costs of capture, transport and storage separately. The supplementary information indicated that cost and performance data for power plants with CCS were derived from literature sources that largely assumed around 90% capture.

Figure 12 provides the ranges of direct emission intensity for electricity generation for the scenarios reaching 430–530 ppm CO_{2eq} in 2100 in the integrated assessment models considered in IPCC 2014b. By 2050 the emissions intensity will need to be around zero from the average level of 520 kg/MWh_e in 2010. This cannot be achieved by technologies that capture only 90% of the CO_2 generated in a power plant.

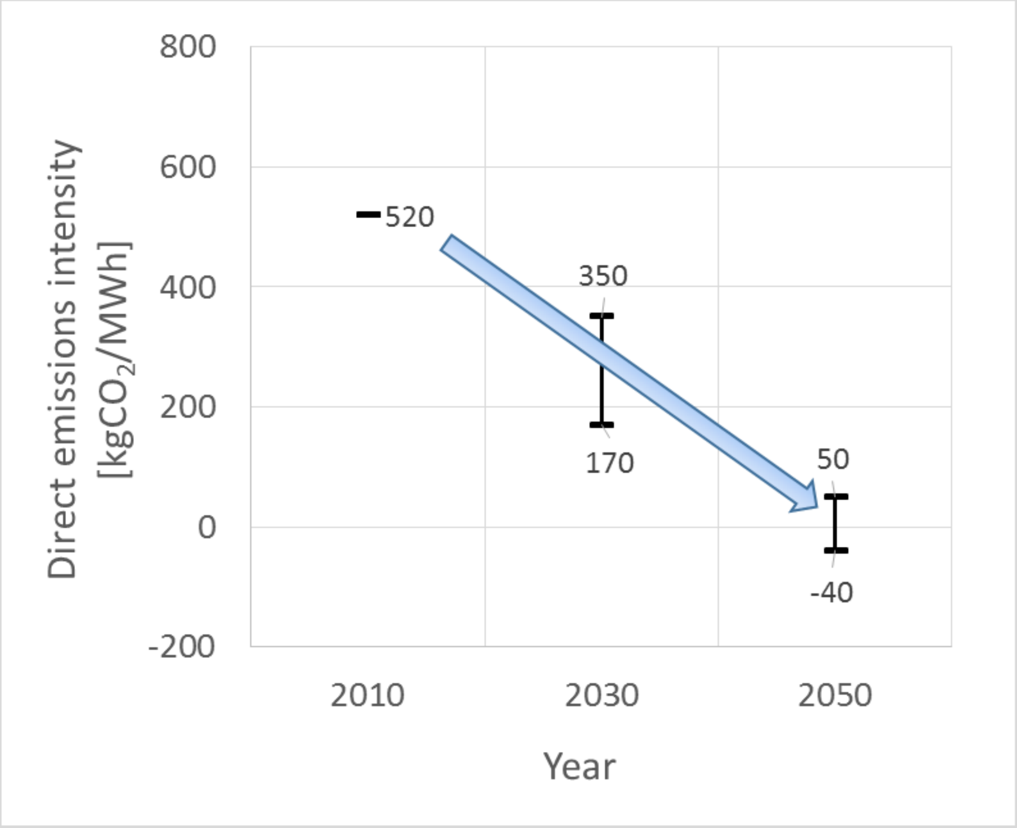


Figure 12 Direct emissions for electricity generation in integrated assessment models reaching 430–530 ppm in 2100 (IPCC 2014b)

More recently the International Energy Agency provided a similar perspective in their Energy Technology Perspectives (IEA 2017) as shown in Figure 13. To keep to a 2 °C trajectory the emissions intensity of new build power station would need to be around 100 kg CO_2/MWh_e after 2020 and approach zero by 2060. For fossil fuel fired power stations, such low emissions can only be achieved through the application of CCS.

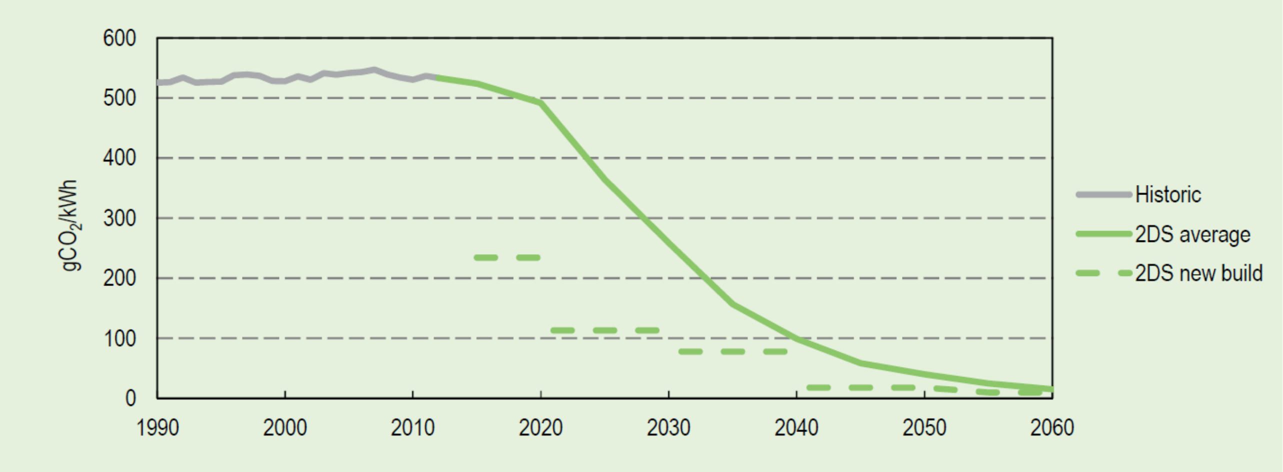


Figure 13 Global fleet average and new-build emission intensity (IEA 2017)

A below 2 °C scenario would require significantly more deployment of CCS. It is anticipated that 32% of additional CO_2 emission reduction would need to be provided by CCS (IEA 2017). It also highlights the benefits of increasing capture rates beyond the usual 90% level. The amount of CO_2 still being emitted at 90% capture constitutes a significant residual emission that would hamper the achievement of zero emissions from power stations by the middle of this century. The use of biomass in achieving zero emissions and even negative emissions constitutes a second pathway to mitigate the residual emissions.

The below 2 °C scenario not only implies higher CCS deployment rates, but also necessitates higher CO_2 capture rates. Many current and emerging capture technologies are designed to remove around 80–90% of the CO_2 from the feed gas, with the remainder vented to the atmosphere. Over time, these emissions would have to be abated as well.

5 Direct and indirect emissions from fossil-fuel-fired power stations with varying degrees of CO_2 capture

In this section, we compare direct and indirect emissions from power plants, and discuss the impact of CO_2 capture rate on both types of emissions. We then describe current efforts to integrate renewable energy into CO_2 capture systems.

5.1 Direct and indirect emissions from power plants

As mentioned in Section 4 the generation of electricity from fossil fuels results in the production of two types of greenhouse gas emissions: direct and indirect.

- Direct greenhouse gas emissions are the CO_2 emissions produced by the combustion or conversion processes within the battery limits of the power-plant facility (including the CO_2 capture and compression facilities, if present).
- Indirect greenhouse gas emissions predominantly comprise CO_2 and CH_4 emissions associated with infrastructure and the supply chain during mining, extraction, treatment and fuel transportation processes.

The emissions from power plants are usually expressed in terms of an emission intensity, the equivalent CO_2 emission per unit output, i.e. (kg CO_2eq/MWh_e). Varying the CO_2 capture rate will affect the direct and indirect emission intensity in different ways, as described below.

For power plants without CO_2 capture, the direct emission intensity is proportionally dependent on the carbon content of the fuel, and inversely proportional to the energy conversion efficiency. Due to the higher carbon content of coal and its lower conversion efficiency, coal-fired power stations have much higher specific emissions than gas-fired combined cycles. The direct emission intensity will be reduced in power plants with CCS, but to a lesser degree than the capture rate. This is because the energy requirement of the capture process will result in an efficiency decrease of the power station.

The indirect emission intensity is dependent on the fuel type, the energy conversion efficiency and industrial practices used throughout the fuel chain. For coal, methane emissions during mining are a significant contributor to the indirect emissions. Natural gas generally contains CO_2, which will often be separated prior to transport and is normally vented. The exploitation of gas wells also produces fugitive CH_4 emissions with other emissions occurring during treatment and transport. When transport is in the liquid form, further emissions are associated with the energy required for the liquefaction. In all cases, emissions are also associated with energy embodied in the plant and equipment. The indirect emissions vary significantly across the same fuel type and are determined by industrial mining and exploitation practices.

Direct emissions dominate the greenhouse gas emissions from fossil-fuel-power plants, whereas for the nuclear and renewable energy technologies, indirect emissions associated with the infrastructure and supply chain are dominant, as shown earlier in Figure 10.

It is important to understand the impact of a variation in CO_2 capture rate on both the direct and indirect emissions. In this section, we use amine-based post-combustion CO_2 capture (PCC) applied to a fossil-fuel-fired power plant with subsequent geological storage of the product CO_2 as the base for analysing direct and indirect emissions at different capture rates. We assume that the capture energy requirement is met by the host power plant. The emission intensity (kg CO_2/MWh_e) takes into account the reduced output of the power plant as a result of the energy requirement for the capture process. As the capture processes for coal and gas-fired power stations are quite similar, we expect that the specific direct emissions for both coal and gas-fired power plants with CCS are reduced to a similar extent at a given CO_2 capture rate.

The indirect emissions from fossil-fuel-fired power stations are strongly linked to the fossil-fuel intensity of the power plant, as quantified by the heat rate. CO_2 capture increases the indirect emissions if the energy required for the capture process is delivered by the host power plant because more fossil fuel is needed per unit of electricity output and the heat rate will therefore increase. The comparative data for direct emissions and lifecycle emissions in Figure 10 indicate that for the power plants with CCS the indirect emissions are of the same magnitude as the direct emissions and even dominant for the gas-fired combined cycle.

5.2 The impact of the CO_2 capture rate on direct and indirect power-plant emissions

The assessment of the effect of CO_2 capture rate on direct and indirect emissions was based on the recommended composition of coal and gas by the IEAGHG R&D program for a coal-fired power plant and a gas-fired combined cycle (See Appendix A**Error! Reference source not found.**). The capture and compression energy requirement was varied between 0.2 kWh/kg CO_2 and 0.4 kWh/kg CO_2. The lower value is twice the theoretical energy requirement (Feron 2010), which is considered to be the best achievable performance for a PCC process (Rochelle 2009). The theoretical energy requirement is based on the summation of the minimum energy requirement for CO_2 separation and compression (see also Section 8.1). The upper value has been determined from a number of full-scale assessment studies (Rubin *et al.* 2015) as a representative value for a conventional monoethanolamine (MEA)-based process. The methane emissions were estimated using the average factors provided in IPCC 2014a for coal and gas extraction and transport. The emission intensity associated with the infrastructure and supply chain was also taken from this reference. Two capture rates were considered: 90 and 99%. An overview of the data used in the assessment is given in Table 8.

Table 8 Data used for calculation of direct and indirect emissions for coal and gas-fired power plants

Power plant	Coal-fired	Gas-fired combined cycle
Capture energy requirement [kWh/kg CO_2]	0.2 – 0.4 (Typical value: 0.3)	0.2 – 0.4 (Typical value: 0.4)
Efficiency without CO_2 capture [-]	0.3 – 0.5	0.4 – 0.6
Methane emission from fuel extraction[7] [g CH_4/MJ]	0.05 (Open cast mine) Range : 0.025–0.068[8]	0.52 Range: 0.18–1.03
Infrastructure and supply chain[9] [kg CO_2/MWh_e]	No CCS: 9.6 With CCS: 28	No CCS: 1.6 With CCS: 8.9
CO_2 capture rate	90%, 99%	90%, 99%

The estimated emission intensities for the coal-fired power stations without and with CO_2 capture are provided in Figure 14. The line ranges for the plants with CO_2 capture reflect the original plant efficiency, with the reduction in efficiency determined by the capture rate and energy requirement for the capture process.

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[7] Global Warming Potential for methane is 21 times that of carbon dioxide on 100 year timeframe.

[8] For underground coal mines the average methane emission is significantly higher at 0.34 (range: 0.25-0.45).

[9] These values are lowest possible for fossil fuel fired power stations, i.e. in case of 100% CO_2 capture and zero fugitive emissions.

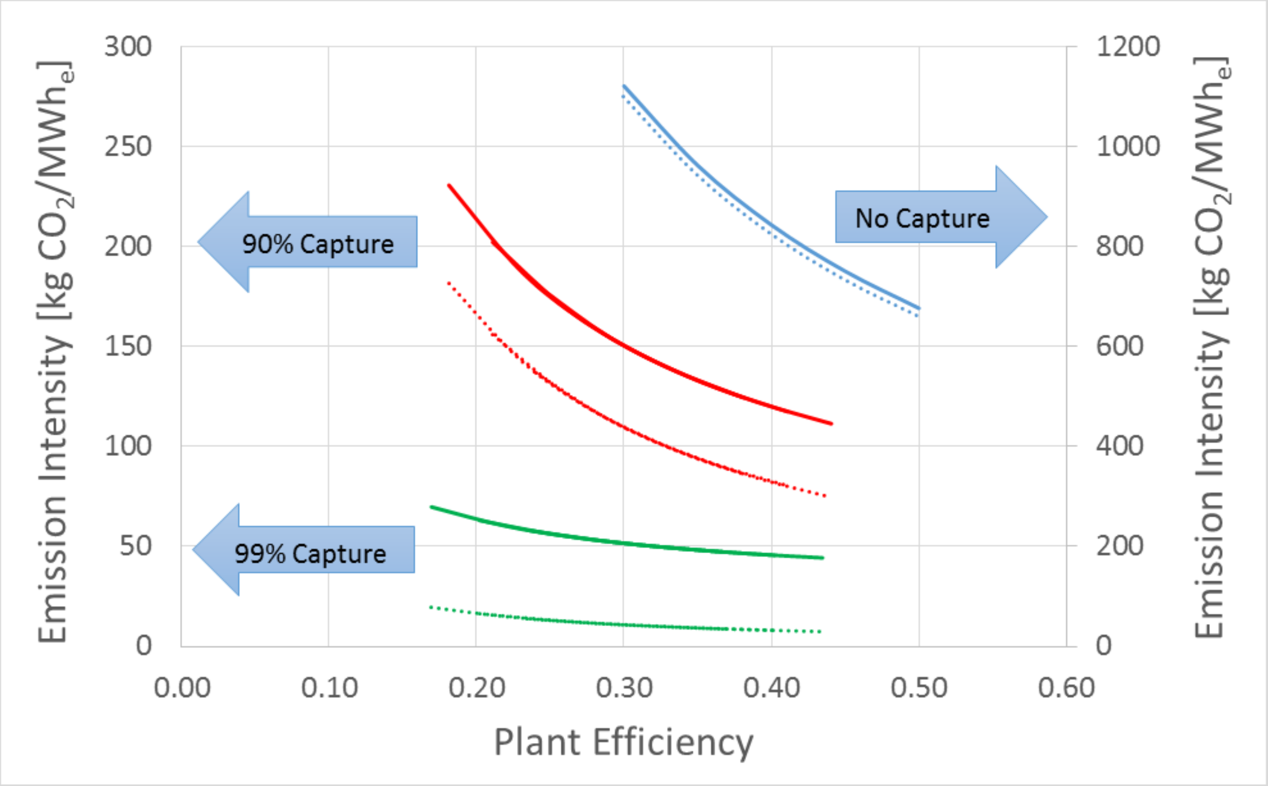

Figure 14 Total (solid line) and direct (dotted line) emission intensity for coal-fired power stations at 90% and 99% capture and no capture

For coal-fired power plants without CO_2 capture, the total emission intensity is largely determined by the direct emissions. With the application of CO_2 capture, the emission intensities are significantly reduced but the emission intensity only reaches levels close to the renewable energy emission intensity (<50 kg CO_2/MWh_e, i.e. “zero emission” in accordance with Table 1) at 99% CO_2 capture. At this capture rate the emission intensity is dominated by the indirect emissions; at 90%, there is also a significant contribution from the indirect emissions. This means that further emission reductions would be more effectively obtained from other actions, such as reducing the methane emission from coal mining, than from further improvements in the capture rate (>99%). Indirect emissions also have high variability depending on the coal source, with fugitive methane emissions from underground mines being nearly seven times larger on average than from open cast mines.

The estimated emission intensity for the gas-fired combined cycle without and with CO_2 capture are provided in Figure 15.

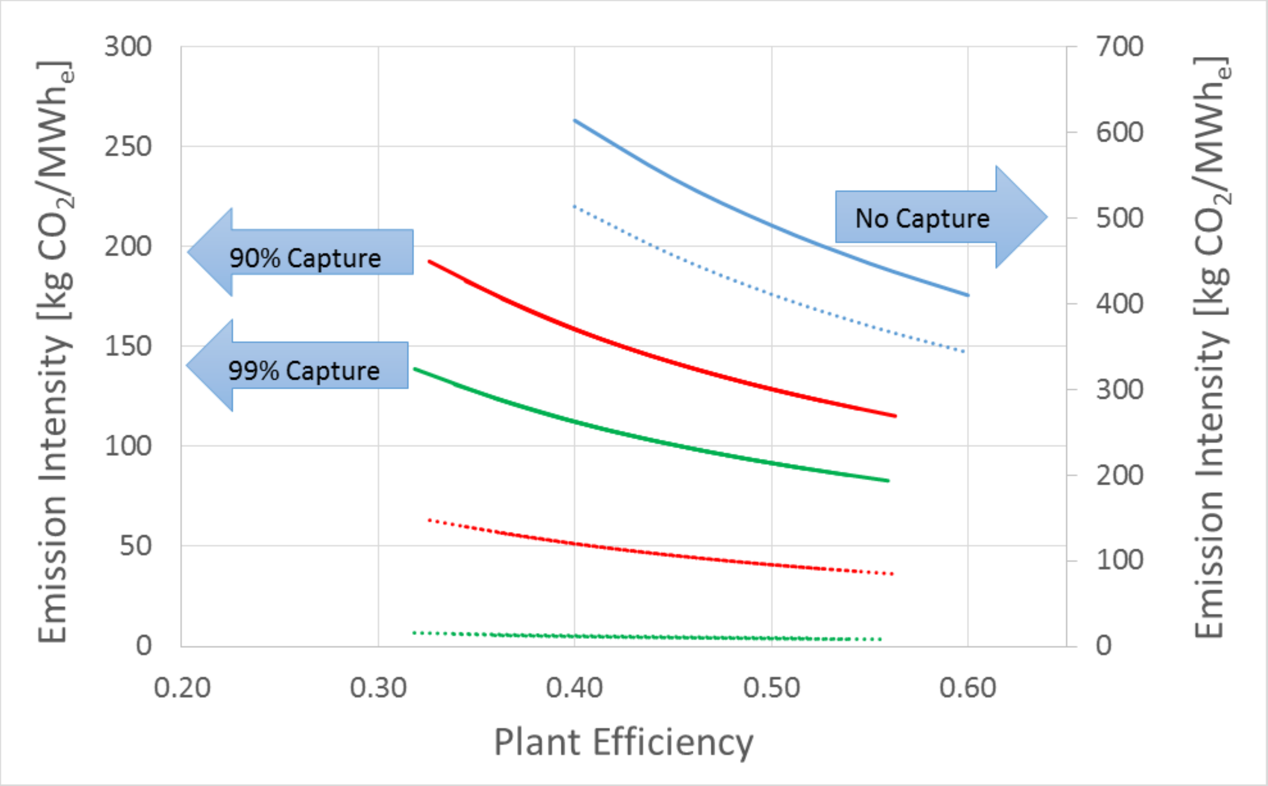

Figure 15 Total (solid line) and direct (dotted line) emissions for gas-fired combine cycles at 90% and 99% capture and no capture

Figure 15 shows that the gas-fired combined cycle without CO_2 capture has a sizeable contribution from the indirect emissions, although direct emissions are dominant. This clearly changes when CO_2 capture is applied. At 90% CO_2 capture, indirect emissions constitute the largest contribution, while at 99% CO_2 capture the direct emissions are almost negligible compared with the indirect emissions. This confirms the need to reduce the fugitive emissions from gas extraction and transport processes to achieve overall low greenhouse gas emissions from the natural gas chain.

A comparison of the natural gas and coal fossil fuel to electricity chain is given in Table 9 using the state-of-the-art power plant efficiencies, capture technology energy requirements and using the averages for indirect emissions from IPCC 2014a. We assumed that the capture energy requirement was identical at 90% and 99% CO_2 capture. The ranges for the emission intensity data found in the literature are also given in Table 9 (IPCC 2014b). These are based on CO_2 capture rates of around 90%.

Table 9 Emission intensity comparison of state-of-the-art fossil-fuel-fired power plant and capture technology performance

Power plant	Coal-fired		Gas-fired combined cycle	
Efficiency without CO_2 capture [-]	0.45		0.60	
Direct emission intensity [kg CO_2eq/MWh_e]	732		343	
Indirect emission intensity [kg CO_2eq/MWh_e]	18		67	
Total emission intensity [kg CO_2eq/MWh_e]	750		410	
Total emission intensity Literature data range (IPCC 2014a) [kg CO_2eq/MWh_e]	740 – 910		410 – 650	
Energy requirement CO_2 capture [kWh/kg CO_2]	0.3		0.4	
CO_2 capture [%]	90	99	90	99
Efficiency with CO_2 capture [-]	0.361	0.352	0.526	0.519
Direct emission intensity [kg CO_2eq/MWh_e]	91	9	39	4
Indirect emission intensity [kg CO_2eq/MWh_e]	38	39	84	85
Total emission intensity [kg CO_2eq/MWh_e]	130	48	123	89
Literature data range (IPCC 2014a) [kg CO_2eq/MWh_e]	190 – 250		94 – 340	

Table 9 shows that emission intensities are lower for coal-fired power stations with 90% CO_2 capture and without capture compared to the literature data range. This is most likely due to the literature data covering a wide range of power stations, including sub-critical power stations with lower efficiency than the state-of-the-art power station efficiency used in this study. The coal used in the IEAGHG R&D studies is also derived from an open cast mine, resulting in lower methane emissions than the literature data which represents a mix of open cast and underground mines. For the gas-fired combined cycle the total emission intensities for the cases with 90% CO_2 capture and without capture are in the lower range of the literature data, reflecting the chosen state-of-the-art power plant performance.

The results for 99% CO_2 capture indicate a higher total emission intensity for the gas-fired combined cycle compared to the coal-fired power stations, which is entirely related to the high fugitive emissions associated with gas extraction and transport. At 99% CO_2 capture the emission intensity for the gas-fired combined cycle is 10 times the minimum achievable as indicated in Table 8, i.e. the emissions related to only infrastructure and supply chain, 8.9 kg CO_2/MWh_e. For the coal-fired power station the emissions intensity is approximately 70% higher than the minimum achievable based on the data in Table 8. The direct emissions for the gas-fired combined cycle remains more than half that of a coal-fired power station and are nearly negligible. At 99% CO_2 capture the indirect emissions constitute 81% of total emissions intensity for a coal-fired power station and 96% for a gas-fired combined cycle. Increasing the capture rate should therefore go hand-in-hand with efforts to reduce the indirect emissions in particular the fugitive emissions from coal and gas. At 99% CO_2 capture the indirect emissions from both coal and gas fired power stations, 39 and 85 kg CO_2/MWh_e, respectively, are higher than the median (indirect) emissions reported for renewable energy (excluding biomass) and nuclear energy plants which are in the range 11-48 kg CO_2/MWh_e as shown in Figure 10.

In Figure 16, the emission intensity data from Table 9 are summarised as a function of CO_2 slip expressed as a percentage (= 100% - CO_2 capture rate). As the slip is reduced from 10% to 1% the direct emissions become very small. At 1% CO_2 slip, the overall emissions are dominated by the indirect emissions, which are 85% larger for the gas-fired combined cycle. The minimum values indicated in Figure 16 are the indirect emissions component that is associated with the infrastructure and supply chain. These values are given in Table 8 and originate from IPCC 2014a.

The analysis above was based on the use of median data on indirect emissions from IPCC 2014a and the coal and gas specification commonly used in IEAGHG studies (See Appendix A). The results are dependent on the type and origin of the fuel.

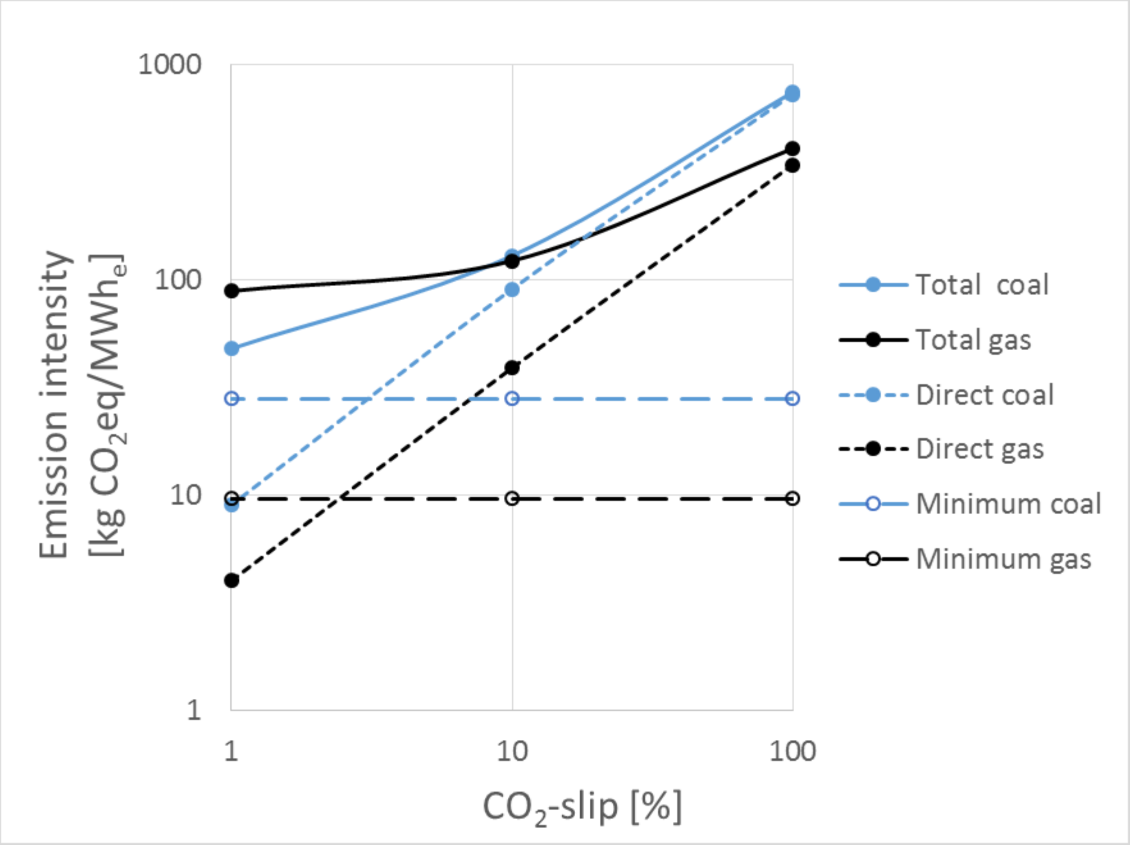

Figure 16 Emission intensity as a function of CO_2 slip from coal and gas-fired power plants

5.3 Integration of renewable energy into a CO_2 capture system

The introduction of CO_2 capture technology in new power plants or in retrofit applications normally reduces the conversion efficiency. This reduction can be prevented if the capture energy requirement is met by an external, low emission energy source. It might also have other benefits. For instance, the extraction of steam needed to regenerate an amine solution will require modifications to the steam cycle, which are avoided if an external steam source such as from a solar thermal field or biomass combustion is available (Khalilpour *et al.* 2017). Advanced systems using solid sorbents operating at high temperatures have also been considered for integration with a high-thermal solar-energy conversion system (Liu *et al*. 2017).

IEAGHG explored the potential for integrating solar-energy technologies with CCS (IEAGHG 2012). Concentrated solar thermal for solvent regeneration and other plant-heating duties was identified as the most promising combination. This would remove the need for extracting steam from the power-plant steam cycle, and its associated costs. They estimated that integrating solar energy would reduce the penalty to the host power station by 3%.

CSIRO evaluated the use of concentrated solar thermal energy to provide the regeneration energy requirement for a pilot-scale PCC plant. This was a world first demonstration coupling renewable energy technologies into PCC processes. Lessons learned included the need to design PCC processes appropriately for integration with a variable renewable energy source; the need for dynamic modelling; and the ability to operate the plant at varying loads depending on solar availability. Heat loss was also noted to be particularly challenging for the pilot-scale operation (McGregor *et al.* 2015).

In the context of this study, the use of renewable energy sources for CO_2 capture was assessed. For simplicity, we assumed that the renewable energy source was essentially emission free. Using the data for a state-of-the-art, coal-fired power plant and a gas-fired combined cycle (Table 9) and the input data for the emission calculations (Table 8) an estimate was made for the direct and indirect emissions for a power plant with CCS with the capture energy provided by a renewable energy system. This meant that the power plant did not have a reduction in efficiency and the specific amount of fossil fuel supplied (heat rate) was identical to the case without CO_2 capture.

Table 10 indicates that emissions could be reduced further by supplying the capture energy through renewable energy sources. For coal-fired power stations additional reductions of 15% at 90% CO_2 capture and 8% at 99% CO_2 capture are possible. For gas-fired combined cycles, the additional emission reductions were 11% at 90% CO_2 capture and 12% at 99% CO_2 capture. This resulted mainly from the maintenance of the higher efficiency that avoided the large increase in indirect emissions, which are more significant in gas-fired power stations than in coal-fired power stations.

Table 10 Emission intensity comparison for state-of-the-art fossil fuel fired power plant and capture technology performance with capture energy provided by a renewable energy system (numbers in parentheses for system without renewable energy input)

Power plant	coal-fired		Gas-fired combined cycle	
Efficiency without CO_2 capture [-]	0.45		0.60	
Direct emission intensity [kg CO_2eq/MWh_e]	732		343	
Indirect emission intensity [kg CO_2eq/MWh_e]	18		67	
Total emission intensity [kg CO_2eq/MWh_e]	750		410	
Energy requirement CO_2 capture [kWh/kg CO_2]	0.3		0.4	
CO_2 capture [%]	90	99	90	99
Efficiency with CO_2 capture by renewable energy [-]	0.45 (0.361)	0.45 (0.352)	0.60 (0.526)	0.60 (0.519)
Direct emission intensity [kg CO_2eq/MWh_e]	73 (91)	7 (9)	34 (39)	3 (4)
Indirect emission intensity [kg CO_2eq/MWh_e]	36 (38)	36 (39)	74 (84)	74 (85)
Total emission intensity [kg CO_2eq/MWh_e]	110 (130)	44 (48)	109 (123)	78 (89)

6 Biomass for emission reduction in power plants

This section explores the use of biomass, or plant matter, for reducing emissions from power plants. We introduce different sources of biomass, and describe the role of bioenergy in global primary energy and electricity generation. Technologies used to generate electricity from biomass and its role in reducing emissions are described, followed by a review of the two main methods for producing power from biomass: combustion and gasification.

6.1 Sources of biomass

The main sources of biomass are organic, plant-derived materials in which solar energy is stored via the process of photosynthesis. These include:

- forestry products (e.g. fuel woods, wood chips) from short rotation plantations
- purpose grown oil-bearing energy crops for bio-liquid fuels production (e.g. rapeseed, jatropha, camelina)
- forestry by-products and residues (e.g. saw dusts, barks and branches)
- agricultural residues (e.g. straw, cane trash), agricultural processing residues and by-products (e.g. rice husk, bagasse, nut shells).

Other sources also include farm animal wastes, human sewage, food-processing wastes, organic components of municipal solid wastes and other organic waste streams such as green wastes.

Biomass can be classified in different ways. According to Verma *et al.* (2017), biomass is classified as woody biomass (e.g. tree, bamboo, plants), non-woody biomass (e.g. grass, stem and roots, cotton), process waste (e.g. bagasse, saw mill waste) and processed fuel (e.g. charcoal, biogas, producer gas). Another approach is to group biomass into three categories according to their potential end uses and conversion methods, i.e. solid, gaseous and liquid biomass. Solid biomass mainly includes woody biomass and process residue (e.g. rice husk, bagasse) that can be used in thermochemical-conversion-based (e.g. combustion, gasification) power plants, mainly to produce heat and electricity. Gaseous biomass is produced from low-energy-density biomass with high moisture contents, such as animal manures, municipal solid wastes and green wastes which are converted into biogas via a biochemical conversion method (e.g. anaerobic digestion). Liquid biomass mainly contains oil-bearing energy crops that can be transformed into bioliquid fuels via biochemical routes (e.g. enzymatic hydrolysis, fermentation).

6.2 Role of bioenergy in global primary energy and electricity generation

Since the start of the industrial revolution, worldwide use of fossil fuels (coal, oil and gas) has increased steadily, leading to a speedy growth of atmospheric CO_2 levels. Coal still plays the role of the dominant fuel for global electricity generation, in spite of environmental impact concerns and greenhouse gas emissions. According to an IEA report (IEA 2017d), coal alone contributed 39.3% of total global electricity generated in 2015. One of the effective ways to reduce global greenhouse gas emissions is to replace fossil-fuel-derived power stations with renewable-based electricity generation plants. In 2015, the total renewables (non-fossil and non-nuclear) share was 22.8% of global electricity generation (IEA 2017d) with the majority (~70%) contribution coming from hydro (IEA 2017b; World Energy Council 2017) followed by wind (~16%), bioenergy (~9%) and solar PV (5%) (IEA 2017b).

The development and deployment of renewable energies worldwide has increased significantly and rapidly, especially in the last two decades. However, the current share of renewables in global electricity generation is quite similar to that of around 40 years ago; in 1971, the contribution from total renewables to global electricity generation was 23.5% (IEA 2017d)]. This is mainly due to increases in global electricity consumption being mostly met by fossil-fuel resources.

Being the oldest primary energy source known to humans, bioenergy plays a very important role in today's energy system and stands as the largest renewable energy source, at 11% (46 EJ) of the global final energy consumption (IEA 2017b). This is approximately 3.5 times larger than total global hydropower supplies. However, in the electricity generation sector, the contribution from bioenergy is ~2% of global electricity consumption, which is only one-eighth of the total contribution from hydroenergy.

Figure 17, which shows the global bioenergy consumption by end use, reveals that only a small portion (~4%) of global bioenergy is currently utilised for electricity generation. According to Lauri *et al.* (2014), biomass is mostly used for domestic cooking and heating in developing countries, where two-thirds of global biomass is inefficiently used, while the remainder is applied in large-scale industry using more advanced technologies such as modern combustors and boilers producing steam and heat for industrial uses and district heating.

The unique characteristic of bioenergy compared with other renewable energy sources is that it can be transformed into high-value gaseous, liquid and solid fuels (Toklu 2017). It is an important renewable source of transport fuels (e.g. bio-ethanol and bio-diesel) to reduce oil dependency, and to reduce and replace fossil fuels suitable for planes, marine vessels and heavy-duty road transport. Global bio-transport fuel production has increased in the past decade, and currently provides approximately 4% of the world's fuels for road transport. Worldwide biofuel production reached 137 billion litres in 2016 which is 30% higher than production total in 2010 (IEA 2017c).

Figure 17 shows that 6% of total global bioenergy is used to generate biofuels for the transport sector.

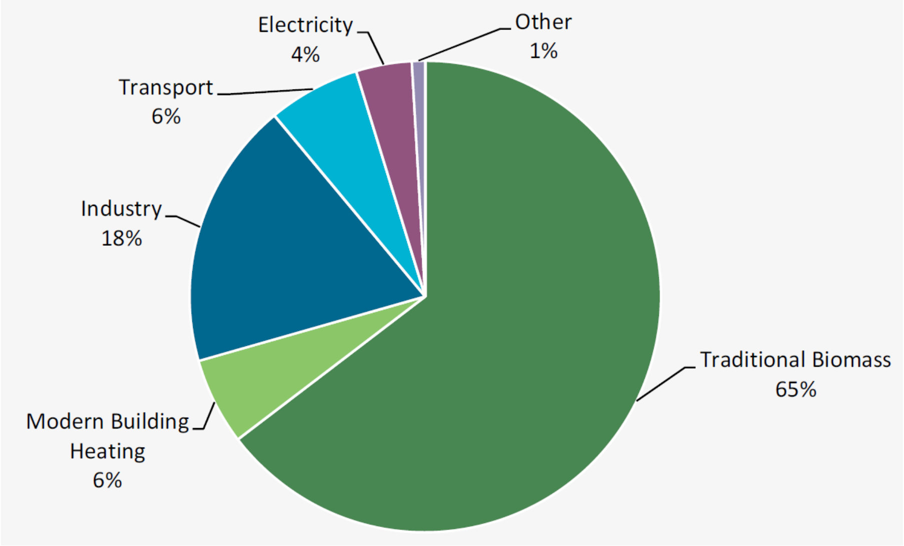

Figure 17 Bioenergy in final energy consumption by end use (IEA 2017b)

6.3 Technologies used for generating electricity from biomass

Among the thermochemical-conversion technologies, direct combustion is the most common and simplest method. The direct combustion method uses excess air to ensure the complete combustion of biomass fuels. Heat from hot flue gases can be used to produce steam, which drives a steam turbine for electricity generation, mostly via the Rankine (steam) cycle. To utilise the biomass more efficiently, most combustion-based plants, particularly in Europe, operate in combined heat and power (CHP) mode. They generate electricity together with heat and steam, which is usually supplied to a local district heating network or industrial application. Direct combustion methods are proven for the production of electricity from biomass fuels. One of the advantages of combustion is that it requires less fuel preparation (e.g. drying), as modern combustors can operate with biomass feeds with high moisture content of up to 55% (in some cases, up to 60%) (EPACHP 2007).

Gasification and pyrolysis are more advanced technologies that can provide higher efficiency than the direct combustion method when converting biomass into electricity. Pyrolysis produces high value biomass products such as charcoals, bio-oils, under medium-temperature operating conditions in the absence of oxidants. During pyrolysis, combustible gases are produced that can be theoretically applied to generate electricity. Bio-liquid fuels produced by fast pyrolysis can be used in both small-scale power generation systems and in large power stations (co-firing) (Chiaramonti *et al.* 2007).

Gasification uses a limited amount of air, resulting in a partial oxidation process that produces a syngas. The syngas can be used to generate electricity in internal combustion engines and gas turbines via a Brayton cycle. End products other than heat and electricity, such as synthetic natural gas (SNG), liquid fuels, fertilizers, chemicals and hydrogen can also be produced. However, gasification requires a significant amount of upstream and downstream pre-treatment and process controls (e.g. reducing moisture content of biomass down to less than 30%, installing a series of syngas-cleaning units prior to power generation) and higher investment cost. For these reasons, even though some medium scale (>1MWe) biomass gasification plants have been planned and deployed in some European countries (Simader 2004; B&W Vølund 2018; Refgas 2018), the majority of biomass-derived power generation plants use combustion technology.

The biomass-conversion pathways used for generating electricity, including the sources of CO_2 emissions, are illustrated in Figure 18.

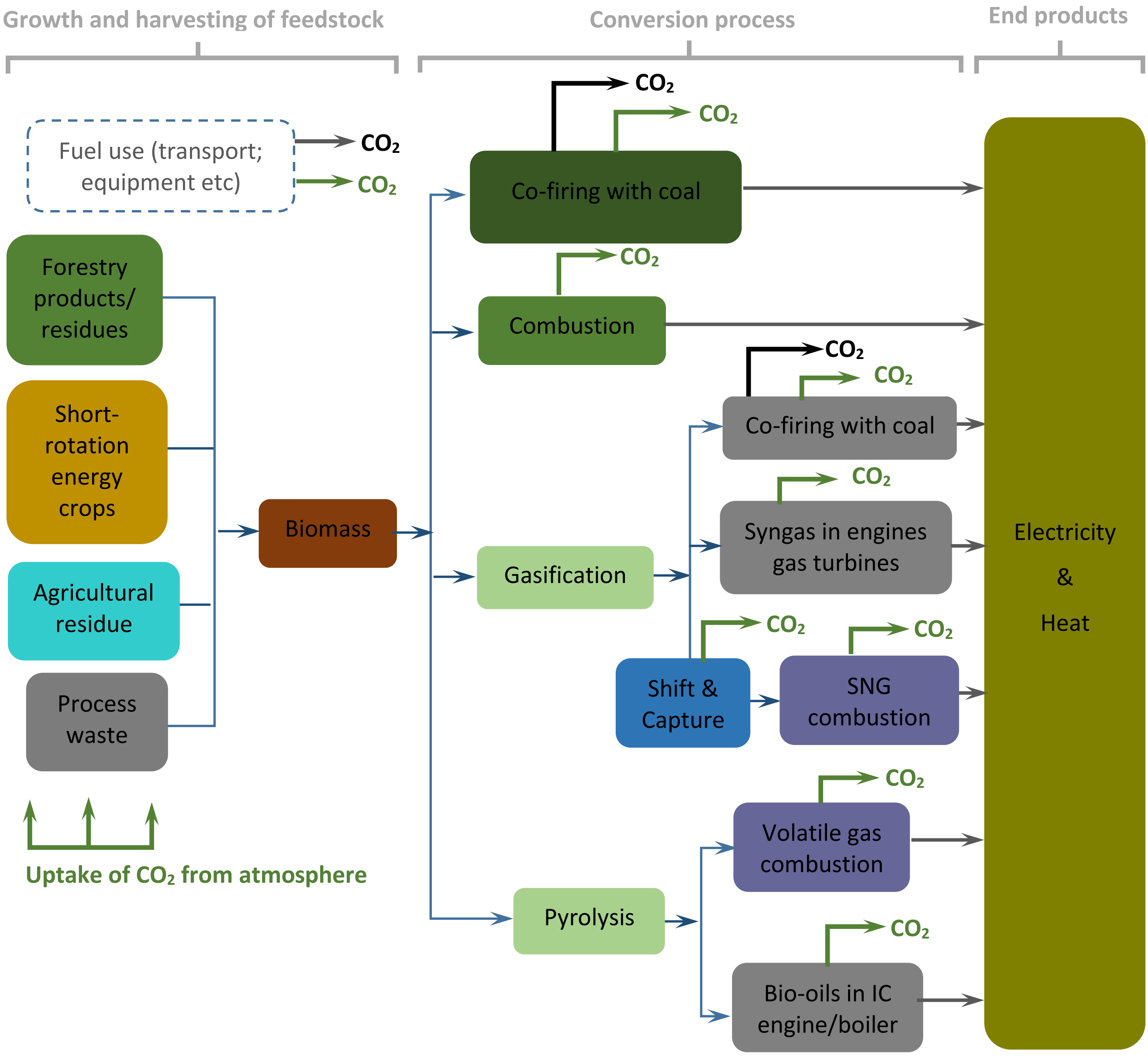

Figure 18 Bioelectricity pathways and sources of CO_2 adapted from (Zakkour *et al.* 2014)

6.4 The role of biomass in reducing CO_2 emissions

During plant growth, CO_2 from the atmosphere is stored as the carbon content of the plant's biomass. When the energy stored in the plant's biomass is used in a thermal power plant, the same quantity of CO_2 previously consumed will be released back into the atmosphere. From this aspect, there is no net increase in atmospheric CO_2 as a result of burning a biomass fuel. Unlike fossil fuels, power production from biomass is therefore often considered to be carbon neutral (Sáez *et al.* 1998; Matthews 2001; Lettens *et al.* 2003; Vande Walle *et al.* 2007; Evans *et al.* 2010; Hosseini and Wahid

2014; Nunes *et al.* 2017; Toklu 2017; Verma *et al.* 2017). If the CO_2 emitted via a biomass power plant is captured and stored, biomass with CCS has been claimed to be one of the few options for negative emissions, as illustrated in Figure 19 (IEAGHG 2011). However, consideration needs to be given to the fossil-fuel usage resulting from fertiliser production, cultivation, collection and transportation of biomass, which means that maintaining 100% carbon neutrality is not easily achievable. According to Evans *et al.* (2010), the estimation of carbon emissions can be complex, especially when land clearing and soil carbon balances are considered, because changing land-use patterns can also affect greenhouse gas emissions.

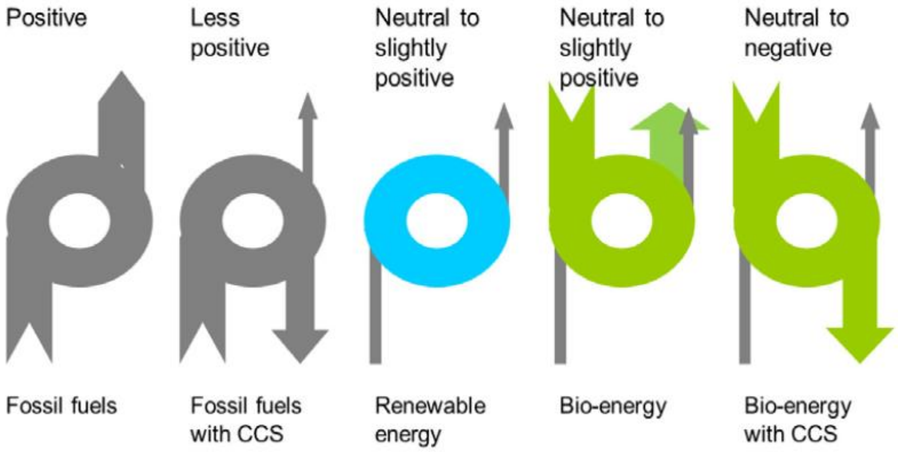

Figure 19 Carbon balance for different energy systems (IEAGHG 2011)

Electricity generation from biomass generally produces low net CO_2 emissions. Evans *et al.* (2010) listed the full life-cycle greenhouse gas emissions from different biomass power generation plants, with the average equivalent CO_2 emission being 63 gCO_2eq/kWh. The highest emissions among those plants was 132 gCO_2eq/kWh from a short-rotation coppice willow electricity plant (Styles and Jones 2007): this is less than 30% of the lowest natural gas plant and 20% of the lowest coal-fired power station emission (Styles and Jones 2007; Evans *et al.* 2010).

The choice of power generation technology plays a part in determining the levels of net CO_2 emissions from biomass. Galbraith *et al.* (2006) compared CO_2 emissions from electricity generation plants using different technologies but similar types of biomass fuel (woodchip). Pyrolysis and gasification-based plant had lower emissions than direct combustion plants, since these more advanced (pyrolysis and gasification) technologies have higher overall efficiency compared to conventional direct combustion plants. The type of biomass also affects net emissions. Using agricultural residues, such as straw, in a combustion-based power generation produced higher CO_2 emissions than similar types of combustion based biomass plants using forest residues and short-rotation energy crops as fuels (Galbraith *et al.* 2006).

6.5 Biomass combustion

Most electricity generated from biomass is produced by direct combustion. While the number of biomass power plants that generate electricity only is limited, most biomass plants operate in a cogeneration mode, producing both heat and electricity, in order to maximise the overall biomass energy utilisation. According to a European report, 75% of biomass plants from EU28 (> 1MW) generate heat only and 22% produce combined heat and power (CHP) (BASIS 2015). Only 3% of biomass power plants in the EU generate electricity only, and most of them are located in southern Europe (e.g. Spain, Italy) where the regional climate is warmer (BASIS 2015). In the United States, more than 60 % of biomass-powered electricity generation is in the form of CHP (EPACHP 2007).

6.5.1 Combustion based Biomass Combined Heat and Power (CHP) System

CHP is not a single technology, but an integrated energy system that can be adapted and customised depending on the needs of the energy users. Suitable waste heat recovery technologies can capture the lower-quality heat, which is usually a by-product from electricity generation. CHP systems can typically achieve gross system efficiencies from 65 to 90 percent depending on the choice of technologies and size of the plant (Obernberger *et al.* 2015).

Modern combustion-based CHP plants are regarded as highly reliable and their availability is reported as 96%. Biomass-based CHP plants in northern Europe are operated almost without interruption all year. In winter, the heat generated from the biomass CHP plant is supplied to the district heating network. In summer, when the thermal production exceeds the customers' heat demand, the buffer storage tank is air cooled to keep the load of the CHP plant high and increase electricity production. Emissions from combustion-based woody biomass CHP plants are low, and usually found to be significantly lower than the regulated emission limits for CO, particulate matter, NH_3 and total organic carbon (Obernberger *et al.* 2015).

CHP systems are mostly established either in cold climates, where demand for district heating is high, or close to industries requiring steam or hot water, such as paper, chemical, wood products and food-processing industries. In other words, the concept and success of establishing any biomass-fuelled CHP project is heavily dependent on the year-round (or most of the year) heat demand. Without a certain average level of guaranteed heat demand, biomass-based CHP plants cannot be economically sustainable. This is highlighted in a report from IEA Bioenergy Task 32 project, which presented the techno-economic evaluation of three selected decentralised CHP applications using biomass as fuels (Obernberger *et al.* 2015). The report selected three CHP plants (Table 11) ranging from 0.13−5.7 MW_e, covering the most relevant capacity range from decentralised biomass CHP plants. The gross thermal capacities of the plants ranged from 0.9 to 17 MW_{th}. The annual gross electric efficiencies of the CHP plants increased with the size of the electricity generation capacity from 10.8% to 22.3%, while the annual total gross efficiencies varied from 69% to 91%.

Table 11 Data from a techno-economic evaluation of three European biomass CHP plants (Obernberger *et al.* 2015)

Parameter	Biomass CHP Plant 1	Biomass CHP Plant 2	Biomass CHP Plant 3
Technology	Steam-turbine	Organic Rankine Cycle	Direct exchange Organic Rankine Cycle
Country	Austria	Estonia	Slovakia
Gross Electricity capacity	5.7 MW_e	2.4 MW_e	0.13 MW_e
Useful Heat capacity	17.0 MW_{th}	9.6 MW_{th}	0.9 MW_{th}
Annual electric efficiency (gross)	22.3 %	16.5 %	10.8 %
Annual thermal efficiency (gross)	46.5 %	74.7 %	58.3 %
Annual overall efficiency (gross)	68.8 %	91.2* %	69.1 %
Specific electricity generation cost	98.6 €/MWh_e	99.7 €/MWh_e 73.3** €/MWh_e	108.8 €/MWh_e
Feed-in tariff	122 €/MWh_e	89.9 €/MWh_e	110 €/MWh_e
Specific heat generation cost	43.7 €/MWh_{th} 41.8** €/MWh_{th}	28.7 €/MWh_{th}	21.1 €/MWh_{th}
Selling heat price	55 €/MWh_{th}	45 €/MWh_{th}	32 €/MWh_{th}

* Annual total efficiency (with condensation), **cost include government funding/subsidy

The amount of heat generated by the biomass CHP plants is significantly higher than the amount of electricity generation: the ratios of gross heat capacity to electricity capacity of the selected plants range from 3−7 MW_{th}/MW_e. The main source of financial benefit from CHP plants is for selling heat generated to the local markets, i.e. as mentioned above, the economic viability of biomass CHP plants essentially depends upon year-round demand and market for heat. Note that the example systems in Table 11 are small in size and would need to be scaled up to have relevance for large coal or gas-fired power plants.

Combustion-based CHP is a proven technology with no major technological challenges. In a steam turbine-based system, the performance of the plant is determined by the quality of steam produced. Applying higher steam pressure and further raising of the steam temperature in advanced steam turbines increases the plant efficiency, but also leads to high temperature corrosion risk. The additional requirements needed to minimise the safety concerns leads to a higher specific investment cost. It is important to keep steam parameters constant as the steam turbine requires stable operation. The fuel mixture should therefore be kept as homogenous as possible. In an Organic Rankine Cycle-based CHP system, the efficiency of electricity generation is limited by the operating temperature of the heat-transfer medium, even though the combined efficiency of heat and electricity is high. One disadvantage of an Organic Rankine Cycle system is that thermal oil used as the heat-transfer medium is flammable, requiring different safety apparatus and procedures to operate the plant compared with a steam cycle system (Obernberger *et al.* 2015).

6.5.2 Co-firing biomass

Co-firing refers to the process of mixing biomass and coal before feeding the mixed fuel to a combustor designed to burn coal. Co-firing is economically attractive, as it can be used in existing coal-fired plants with further fuel cost reduction if the biomass costs at least 20% less than the purchase price of coal (EPACHP 2007). However, due to the different chemical and physical composition of coal and biomass, there is a limit to the maximum amount of biomass that can blend with coal without significant modification to the existing combustion system. Biomass fuels have been successfully co-fired with the amount of biomass (wood chips, wood pellet and pelletized waste paper) ranging from 5 to 15% of the total heat input (EPACHP 2007; Al-Mansour and Zuwala 2010; Livingston *et al.* 2016). When blending a small amount of biomass with coal, no significant changes in boiler efficiency are usually observed. However, researchers have recommended modifying some design and operational parameters, such as increasing overfire air to maximise the boiler efficiency while maintaining acceptable opacity, baghouse performance, and other operating requirements (EPACHP 2007). Without adjustments for co-firing, up to 2 percent boiler efficiency loss was observed at a biomass heat input level of 10% tested in a pulverised-coal boiler (Tillman 2000). However, a recent operation at 112 MW coal-fired power plant in Japan demonstrated that a biomass co-firing heat value ratio up to 34% is achievable using a specially designed boiler equipped with three combustion process (MHPS, 2018). Mitsubishi Hitachi Power Systems (MHPS) claimed that their coal-fired power plant specially designed for co-firing can operate with over 30% of biomass (wood pellet) mixing ratio and can switch from coal to coal-biomass blend without major change of equipment (MHPS, 2018).

The major advantage of co-firing is that it requires no (or very little) added investment for the boiler equipment, and additional operation and maintenance (O&M) costs to the boiler section attributable for adding biomass are minimal. According to EPACHP (2007), maintenance requirements for boilers co-firing biomass and coal are similar to those for coal-only boilers. The main added investment cost and O&M costs are mostly related to fuel handling, processing, storage and the feeding system. As discussed above, some additional cost will be associated with modifications to operational procedures, such as increasing overfire air and fuel feeder speeds.

Wood chips and wood pellets are preferable for co-firing with coal in stoker boilers compared with other types of biomass, particularly mulch-like material. This is because the physical properties of wood chips and pellets are similar to stoker coal in terms of size and flow characteristics. Existing coal-handling systems can therefore be used without any major problems occurring, such as fuel blockages in various areas of the conveying and feeding systems. Another advantage of using woodchips and wood pellets is that they usually contain very low alkali and low chlorine unlike some biomass (e.g. agricultural residues). Fuel with high alkali content (principally potassium) can cause potential fouling and ash deposition on heat recovery systems, while fuel with high chlorine can accelerate corrosion of the combustion system and flue gas clean-up components. It is also important to choose biomass containing mineral matter that does not impact the quality of fly ash that has already been authorised for use as a feedstock for cement and concrete production (Wang and Baxter 2007).

Experience from field trials and commercial plant operations has shown that co-firing with biomass can be achieved using a wide range of existing coal boiler types, including stoker, pulverised coal, and bubbling and circulating fluidised bed boilers (Tillman 2000; EPACHP 2007; Al-Mansour and

Zuwala 2010; Livingston *et al.* 2016). As large-scale, high-efficiency coal-fired power plants are based on a pulverised coal combustion system, understanding the behaviour of biomass in pulverised coal firing systems is important. For a pulverised coal firing system, milling the biomass is a critical step in fuel processing. It can be milled separately, either using existing coal milling systems or using mills designed to pulverise biomass suitable for entrained firing before mixing with pulverised coal. As a biomass milling system can increase the co-firing ratios of biomass, several coal-fired power plants in Northern Europe have adapted this technique especially in newly built pulverised coal power plants. However, this option involves much higher levels of capital investment. The current most common co-firing practice uses the simplest approach, in which coal and biomass are pre-mixed at suitable co-firing ratios before milling with the existing coal mills and then fired through the existing coal firing system. This is the most attractive way to deploy biomass co-firing in existing large-scale pulverised coal-fired power plants, as its implementation requires less time with modest capital investment. Even though the level of substitution of coal is limited to 10-12% with this approach, large volumes of biomass, particularly wood pellets, have been co-fired in this way in most existing coal-fired power plants worldwide (Saidur *et al.* 2011).

Although biomass refers to both woody products and non-woody products, co-firing in large-scale, pulverised-coal plants is mostly suitable for woody material. Non-woody biomass, such as agricultural wastes and the faster-growing biomass materials contain far more mineral matter with a higher levels of alkali metals and lower ash-fusion temperatures (in some case less than 1100 °C) than woody biomass (Li *et al.* 2013). As a result, non-woody biomass is classified in the medium and high slagging category and in the severe fouling category. It is generally unsuitable for firing in large scale, coal-firing systems. If it must be used, it can only be co-fired at low co-firing ratios in boiler plants originally designed for coal. The preferred fuel for large-scale biomass firing in pulverised coal-fired boilers is pelletised sawdust, which is currently traded in very large quantities worldwide. Global wood pellet production surpassed 26 million tonnes in 2015 and the majority of this was consumed in coal-fired power plants in Europe, North American and Asia, particularly Japan and South Korea (Thrän *et al.* 2017). The total moisture content of wood pellets is normally less than 10% and lies within the range of 7–10% (Thrän *et al.* 2017). This would appear to be perfectly acceptable for processing through modified vertical spindle coal mills and firing at most coal power plants. Using only high-quality wood pellets milled in a biomass milling system, higher co-firing ratios of up to 50% on a heat input basis are achievable with the direct injection of the pre-milled biomass into a pulverised coal firing system (Livingston *et al.* 2016).

The economic evaluation of co-firing coal with biomass in existing boilers is complex and associated costing information is limited. A demonstration project in the USA in 1997 reported that capital cost associated with adding the biomass supported facilities in co-firing power plant, can be limited to less than US$200/kW for a boiler capacity larger than 100 MWe (Battista Jr. *et al.* 2000). According to Cantwell (2002), the capital investments associated with the implementation of direct co-firing is 279 USD/kW. A recent literature study stated that the investment cost of retrofitting a coal-fired power plant with biomass co-firing is in the range of 430-500 US$/kW for co-feed plants (in which coal and biomass are pre-mixed at suitable co-firing ratios before milling with the existing coal mills), and 760-900 US$/kW in case of a separate feed system (in which milling of biomass was done separately using a special mill design to pulverize biomass effectively) (Sahu *et al.* 2014).

One of the important economic components is the price of biomass fuel especially when high percentages of biomass are used. Biomass fuel prices can be found within a broad range, depending on location and demand. For example, the cost of feedstock for a pellet plant in Argentina can be four times cheaper than those for an Austrian wood pellet plant (Thrän *et al.* 2017). The recent global pellet market outlook stated that the average price of industrial wood pellets between 2009 and 2016 has been 163 US$ per tonne and prices have been dropping since the beginning of 2015 as a result of oversupply. More recent data showed that the price dropped to 113 US$ per tonne, hitting historical lows (Strauss 2017). A literature study from 2014 showed that the costs for globally traded biomass pellets are around €12/MWh higher than the costs of coal (Sahu *et al.* 2014). Additional cost (capital, fuels and O&M) associated with co-firing in existing coal-fired power plant can be compensated by the value of the CO_2 emission reduction. Bilgili *et al.* (2017) pointed out that government subsidies are crucial for utilizing biomass in existing coal-fired power plant if biomass sources are to be competitive with fossil fuels.

6.5.3 100% biomass firing in pulverised coal boilers

Complete substitution of coal with biomass in existing, large-scale pulverised-coal boilers is possible if particular pre-treatment of selected high-quality biomass is followed. This approach involves milling the biomass into suitable sizes for suspension firing using special milling systems designed to mill biomass, followed by direct injection of the milled biomass into the pulverised-coal conveying system. This could be into modified burners or into new dedicated biomass burners, which requires high levels of capital investment. As this concept allows for 100% biomass in pulverised-coal boilers, interest has been growing in recent years, particularly in the UK, and in northern European and North American countries (Al-Mansour and Zuwala 2010; Agbor *et al.* 2014; Sahu *et al.* 2014; Livingston *et al.* 2016).

According to the recent experiences at several plants, firing 100% biomass showed no significant changes to furnace heat absorption if high-grade pelletised sawdust is used. For that reason, Livingston *et al.* (2016) concluded that there should be no requirement for any significant boiler pressure part modifications when 100% high-quality wood pellets are used for firing. The advantage of good quality pellets is that they contain significantly lower levels of elements such as nitrogen, sulphur and chlorine than most coals. Lower sulphur and chlorine levels would assist in reducing the requirements for acid gas clean-up, and minimises the risk of high-temperature corrosion of boiler surfaces.

The "go/no go" decision making process for firing 100% biomass in coal-firing boilers is mostly determined by the amount and properties of mineral matter contained in the particular biomass considered. Most biomass including both woody and non-woody materials, contain ashes with relatively low ash-fusion temperatures. As mentioned earlier, these are categorised as having a high slagging potential compared with most bituminous coals. Therefore, the major concern of firing 100% biomass is to avoid excessive formation of slag in combustion and boiler systems such as on the final superheater elements, on the platen superheaters, around the burners and on other refractory surfaces in the furnace (Sahu *et al.* 2014). It is therefore important to understand the behaviour of mineral matter by conducting a full ash analysis, including determination of ash-fusion temperatures and investigation of other slagging parameters, such as the viscosity of the biomass slag, of the candidate high-quality wood pellets.

The other concern when firing 100% biomass is the potential for greater ash fouling of the boiler convective pass. This can be caused by deposition of ash largely driven by the volatilisation and subsequent condensation of alkali metals in the fuel ash. To avoid this risk, it is recommended to limit the alkali metal content of the fuels on a kg/GJ basis to such a level that fouling can be managed by the use of existing on-line cleaning systems. Livingston *et al.* (2016) listed the criteria and limits of the quantity and quality of the mineral matter of the biomass intended for use in 100% firing in a pulverised-coal boiler as follows:

- Ash content less than 0.5%,
- Ash deformation temperature (reducing) >1150°C,
- Total $Na_2O + K_2O < 0.17$ kg/GJ, and
- $P_2O_5 < 5\%$ in ash.

For this reason, any wood pellets produced and traded in large quantities are required to be tested and labelled with their basic physical and chemical characteristics, along with the characteristics of mineral matter and some of the important trace elements according to the new European pellets standard, EN 14961-1 (Alakangas 2011). The ash-fusion temperature of the biomass is regarded as the most crucial parameter.

Some power stations in Europe, particularly in the UK, have gradually been converted from their coal-fired power boilers into 100% biomass systems. This includes Drax Power Station in North Yorkshire (England), run by the Drax Group; Ironbridge Power Station in Shropshire (England), by E.O.N.; Avedøre Plant in Denmark, run by Dong Energy.

Drax Power Station, the largest electricity generating plant in UK, was commissioned in the 1970s and 1980s with a total installed capacity of 3960 MW_e. It has six pulverised-bituminous-coal boiler and turbine units with a capacity of 660 MW_e, each. In 2003, co-firing was introduced, and trial operations have been conducted since then using pre-mixing of biomass and coal as the first option. This approach allowed up to around 10% co-firing on an individual boiler. In 2005-2006, a prototype direct-injection, co-firing system was installed. By 2010, a large-scale, direct-injection facility including a transport system, storage, milling and feeding systems was successfully installed and operated to co-fire around 1.5 million tonnes of biomass, equivalent to around 400 MW_e generating capacity. From 2012-2015, three units of the power station were transformed to 100% firing mode using wood pellets. Changes in generation efficiency using 100% wood pellet fuel have been negligible and no significant additional energy loss was observed compared with its original coal-based system (Strauss 2016). A trial run for firing wood pellets in the fourth unit was started in 2017 (Vaughan 2017). Drax Power Station currently generates between half and its full capacity of about 2000 MWe using wood pellets, and these facilities can handle up to 9 million tonnes of wood pellets annually, which is more than 30% of global wood pellet production. The Drax plant is the largest single wood pellet consumer in the world, and produces 17% of the UK's renewable electricity. It is claimed that this plant alone reduces CO_2 emissions by 12 million tonnes per year (Pearce 2017).

6.6 Biomass gasification

Gasification is a thermochemical-conversion process that uses limited air or oxygen to convert solid fuel into gaseous components consisting of combustible species, mainly H_2 and CO, together with small amounts of CH_4. It is a century-old technology; around the mid-19th century, town gas was produced in Europe via gasification of coal and biomass (charcoal) for lighting and heating. The invention of the electric bulb and the rapid development of the oil and gas industry significantly reduced the need for gasification technology. World War II saw the use of a million small-scale, gasifier-engine systems using biomass (particularly charcoal and wood), primarily for production of transportation fuels. As the oil-supply route was cut during the war, synthesis oil was produced from coal syngas via the Fischer-Tropsch process in Germany. The availability of cheap oil from the Middle East after the war completely eliminated the need for gasification for transportation and chemical products (Basu 2010).

More recent interest in gasification was driven by the 1973 oil embargo, which kicked off a strong desire to decrease oil dependency and to produce transport fuels from solid fuels via gasification. These interests were reinforced by the rising awareness of global warming and the threat of climate change in the late 1990s, driving the need for more efficient, cleaner ways to produce electricity, such as integrated gasification combined cycle (IGCC) power plants. Electricity generation via gasification is more efficient than a direct firing process. This is because syngas generated from gasification usually feeds to an internal combustion engine or turbine via a Brayton cycle, which can transform heat to energy more efficiently than steam-only cycle processes.

Since the 1980s, worldwide gasification capacity has been growing gradually. Most growth is occurring in Asia, primarily in China, India and South Korea. According to the Gasification & Syngas Technologies Council, more than 272 gasification plants operate worldwide, with 686 gasifiers producing more than 100,000 MW_{th} synthesis gas (GSTC 2018). The majority of these gasification plants (more than 90% of total capacity) were deployed to produce primarily chemicals, as well as liquid fuels and synthetic natural gas (SNG) to substitute LNG imports, especially in Asia where LNG is very expensive. Only a small capacity of the world’s gasification plants (<7%) generate electricity as a final product (Higman 2014).

Fossil fuels, mainly coal, are the dominant feedstock for gasification projects. Even though some biomass gasifiers are listed in the worldwide gasification database, most of them are much smaller than the typical coal, petroleum or petcoke gasification plants. The current capacity of biomass and waste-gasification facilities combined is estimated at less than 2% of the fossil-fuel-based gasification plants (GSTC 2018).

In principle, gasification is considered as one of the most promising thermochemical-conversion options, due to its potentially high overall efficiency and flexibility to produce different end products. However, biomass gasification is not widely applied for industrial or domestic syngas production. Several barriers to its deployment have been identified in recent studies and overviews, such as pretreatment requirements for biomass gasification, gas conditioning and conversion technology, management of the biomass supply chain, government policies, and utilisation of fuel gas for heat and power (Pereira *et al.* 2012; Ruiz *et al.* 2013; Sansaniwal *et al.* 2017).

Most of these issues (pre-treatment, gas cleaning and economic feasibility) are related to the formation and presence of tars in syngas, which is considered to be the biggest obstacle for biomass gasification to penetrate into commercial markets. Tars form during gasification, and their quantity and composition vary depending on the type of gasification technology and the type of biomass. Biomass tars consist of a variable mixture of condensable hydrocarbons, with or without other oxygen-containing hydrocarbons and more complex polycyclic aromatic hydrocarbons (Michel *et al.* 2011; Pereira *et al.* 2012). Tar from biomass gasifiers can damage and cause unacceptable levels of maintenance for engines and turbines, which leads to frequent unscheduled shutdown of plants. In fact, in the last three decades, numerous investigations aimed at minimising tar from biomass gasification propose modified gasifier designs and, adjusting and optimising operating parameters (Jőnsson 1985; Henriksen *et al.* 1991; Bui *et al.* 1994; Susanto and Beenackers 1996; Bhattacharya *et al.* 2001; Henriksen *et al.* 2006; Chen *et al.* 2009; Gómez-Barea *et al.* 2013).

New, advanced concepts of biomass gasification derived from successful laboratory-scale experiments were reviewed by Heidenreich and Foscolo (2015). They categorised advanced biomass gasification technologies into three concepts: i) integration of gasification, gas cleaning and conditioning, ii) combination of pyrolysis and gasification and iii) combination of gasification and combustion. All these advanced technologies have the same purpose, which is to reduce tar to a level small enough to use in power applications and increase syngas quality.

Tar prevention can be achieved in a gasifier at an operating temperature high enough to break down all tar compounds into the lightest gas species (e.g. CH_4, CO, H_2) (Qin *et al.* 2012; Tremel *et al.* 2013; Schneider *et al.* 2016). This can be considered as trading off tar problems with more elaborate biomass pretreatment and feeding problems (Rabou *et al.* 2009), because high-temperature pressurised entrained flow technologies require for oxygen enrichment.

As almost all biomass gasification technologies practiced so far produce syngas with different levels of tar, downstream gas cleaning to remove the tar is inevitable. The most conventional approach is to remove tar from syngas by scrubbing using a liquid absorbent. Water is primarily used as scrubbing agent, as it is easier and cheaper than other options (Abdoulmoumine *et al.* 2015). Oil-based absorbents are often considered to be an excellent, albeit more expensive, alternative. Another effective approach is the use of catalysts that transform tars into lighter gases, such as CO, H_2 and CH_4. Depending on the operating conditions, catalysts tar removal can be classified into reforming, cracking, hydrogenation and selective oxidation (Shen and Yoshikawa 2013; Asadullah 2014). Unlike scrubbing with liquid sorbents, catalytic tar removal, also known as hot gas cleaning, is usually performed at higher operating temperatures of 350°C to 700°C (Shen and Yoshikawa 2013).

According to Kirkels and Verbong (2011), biomass gasification is not yet mature enough to be widely applied in the market. Therefore, the most effective and scalable way to deploy biomass gasification is to feed the syngas from the biomass gasifier directly into a coal-fired boiler. Gasification can therefore be regarded as a biomass pre-processing method. For direct co-firing, only a limited amount of biomass can be blended with coal without any significant effect on performance of the existing combustion system. Only up to 3% of biomass on an input energy basis can be directly co-fired with minimal additional modification costs and without affecting boiler efficiency (Al-Mansour and Zuwala 2010). One of the main problems with direct co-firing is related to the significant difference between the mineral matter properties of coal and biomass. Biomass ashes contain high alkaline and chlorine levels which can cause corrosion, slagging and fouling in the boiler, heat exchangers and piping. This problem can be solved by applying an indirect co-firing concept via biomass gasification, in which biomass mineral matter does not feed into coal-fired boilers. According to Heidenreich and Foscolo (2015), a syngas equivalent up to 10% of the thermal capacity of the boiler can be co-fired without needing to modify the boiler or auxiliary devices. A further advantage of the co-firing approach concept is that it does not require a highly efficient gas conditioning and cleaning system, as the raw syngas produced is directly burned inside the coal-fired boiler where the purity of syngas is not a concern.

Indirect co-firing has several advantages over direct co-firing:

- less fuel processing is required (e.g. drying, grinding)
- a broad range of biomass, including low quality biomass, can be used
- operation is not dependent on availability of biomass, as it can be simply substituted by fossil fuel (Heidenreich and Foscolo 2015).

The only major disadvantage of indirect co-firing is the relatively high unit investment costs compared with direct co-firing (IEA Bioenergy 2018).

The first demonstration of biomass gasification/co-firing was in the coal-fired Kymijärvi CHP plant in Lahti (Finland). The maximum electricity-generating capacity of the plant is 167 MW_e together with 240 MW_{th} of district heating production. In 1997, the existing coal-fired boiler was integrated with a commercial-scale, atmospheric, circulating fluidised-bed (nominal capacity 50 MW_{th}) for indirect co-firing using low-quality, wet biomass fuels (wood residues, saw dust and recycled fuel). The first two years of operation in 1998-1999 demonstrated that indirect co-firing of hot, raw and very low calorific product syngas in an existing coal-fired boiler is technically feasible (Raskin *et al.* 2001).

The Lahti plant proved that indirect co-firing is an effective way to apply biomass gasification technology to generate heat and power in an existing coal-fired boiler. Several plants followed their success to deploy further indirect co-firing systems, including:

- an 83 MW_{th} circulating fluidised-bed (CFB) Lurgi gasifier deployed for indirect co-firing in a 600 MW_e and 350 MW_{th} CHP plant in Amergas power plant, Geertruidenberg, The Netherlands, in 2002 (Carbo 2017)
- the Electrabel Ruien power plant in Belgium with a similar capacity to the Lahti plant's CFB gasifier; 9% of the coal is substituted by a syngas on a nominal basis (Ryckmans and Spiegel 2004).
- a 140 MW CFB gasifier installed at the 560 MW_{th} coal-fired power plant in Metso Vaskiluodon Voima, Vaasa, Finland in 2013 substituting 25% and 40% of coal consumption by forest residues (IEA Bioenergy 2018). This is the world's largest biomass gasifier to date (Heidenreich and Foscolo 2015).

6.7 Summary

Bioenergy is an important source of the world's primary energy requirements, but only a small portion (~4%) is used for power generation. Using biomass for power generation is considered as carbon neutral, because the CO_2 released was previously stored during plant growth.

Combustion is the dominant proven technology for generating power from biomass, with modern combustion-based CHP plants having high availability and overall efficiency. The majority of electricity generation from combustion-based biomass CHP plants occurs in Europe and the United States. A major drawback of biomass-derived CHP plants is that their deployment is highly dependent on a consistent heat demand for most of the year. Plants in regions such as Europe, however, can operate year-round without any significant issues.

A simple and effective way to substitute fossil fuels with biomass is by co-firing biomass in existing coal-fired power plants. Due to significant differences in physical and chemical properties of biomass and coals, only a small amount (up to 3%) of biomass on a thermal basis can be co-fired without reducing the performance of a coal-fired boiler. For existing conventional coal-fired boilers, with some modifications in design and operational parameters, woody biomasses (wood chips and pellets) can be blended with coals in a range of 5−15% of the total energy input and directly co-fired in a coal-fired boiler. In the co-firing process, the added costs of modification, operation and maintenance due to adding fuel are small compared with the costs of fuel handling, processing, storage and the feeding system. This is more significant for large-scale plants using pulverised coal.

Milling biomass is an important step in large-scale co-firing systems. It can be done either using existing coal-milling equipment (for lower co-firing ratios) or using a mill specially designed for pulverising biomass (for higher co-firing ratios). One of the drawbacks of direct co-firing is that coal-fired boilers and heat-exchange systems are sensitive to biomass mineral matter with higher levels of alkali metals and lower ash-fusion temperatures. Successful direct co-firing therefore depends on selecting biomass with a low mineral matter content and relatively higher fusion temperature. For high-quality wood pellets, firing 100% of biomass in pulverised-coal-fired plants is feasible, and is practiced in England’s Drax Power Station.

Biomass gasification may appear to be a more promising technology than combustion, because it can provide higher efficiency with product flexibility. However, in practice, a highly efficient reactor design is yet to be developed for sustainable and successful commercial operation – despite more than 30 years’ extensive R&D and demonstration attempts, and the availability of different gasification technologies (fixed beds, fluidised beds and entrained flow). Technological barriers to biomass gasification include tar reduction, gas cleaning and scale-up. The most promising approach for large-scale commercial application is indirectly co-fired syngas from biomass gasification in the existing coal-fired boilers, because it is not sensitive to the purity and quality of the biomass-derived syngases.

7 CO_2 capture technologies

The CO_2 capture technologies described in this section include liquid absorbents, solid sorbents, membranes and refrigeration.

7.1 Liquid absorbents

CO_2 capture technologies based on liquid absorbents are leading in both post- and pre-combustion capture, despite the significant differences in CO_2 partial pressures in these two applications. At low partial pressures, such as in flue gas, chemical absorption is preferred, while physical absorption is preferred at elevated pressures (Feron and Puxty 2011).

7.1.1 Chemical absorption

Chemical-absorption based processes are the most technologically advanced for post combustion capture (PCC) of CO_2, having already been used widely in the gas-processing industry. Absorbents are typically blends of aqueous amines, but can also include amino-acid salts, ammonia, ionic liquids and enzyme-enhanced processes. CO_2 capture efficiencies are generally in the range of 85-90% (IEA GHG 2006).

Chemical-absorption-based PCC technologies have been trialled at a range of coal and natural gas facilities (GCCSI 2012) and scaled up to a megatonne per annum scale, as evidenced by the Boundary Dam plant in Saskatchewan, Canada and the PetraNova project in Texas, United States. It is currently the leading capture technology for power plants; the detailed impact of increasing capture rates is further discussed in Section 8. Previous work as summarised in Section 2 indicates that higher capture rates can be achieved, but at a greater cost and with higher specific energy requirement.

7.1.2 Physical absorption

Physical-absorption-based removal of CO_2 from high-pressure gas streams is already widely practiced in industry. Commercially available physical absorption processes include Selexol and Rectisol. Such processes can capture up to 95% of the CO_2 from a feed gas stream. However, as a result of incomplete conversion of CO to CO_2 in the gasification and shift reactors, the overall plant CO_2 capture efficiency tends to be in the range 85-90% (IEA GHG 2006).

An IEAGHG report into CO_2 capture at coal-based power and H_2 plants determined that CO_2 capture from an IGCC process could be increased from 90 to 98% while reducing the cost per tonne CO_2 by 3% (IEAGHG 2014a).

7.2 Solid sorbents

Capturing gas emissions with solid sorbents involves preferential adsorption of one gas component (here CO_2) from a mixed feed stream (e.g. combustion flue gas, steam methane reforming and water-gas shift reaction) at a certain operating pressure and temperature, followed by regeneration or desorption of the adsorbed component at either a reduced pressure or increased temperature (or combined). Major developments in the emerging solid sorbent systems are usually linked to the properties of adsorbent materials and process configurations (Table 12).

Table 12 Classification of solid sorbent systems

Adsorbent material	Process configuration & operation
Physical and chemical adsorbents • Low temperature adsorbents - Activated carbon including biomass derived carbon - alumina, zeolites and meso-porous silica - metal organic framework - alkali metal carbonates - ion-exchange resin - coal fly-ash - surface modified porous media - clathrates/hydrates • High temperature adsorbents - Metal oxides - lime - dolomite - hydrotalcites - zirconates - perovskites	Fixed and moving bed reactors including rotating beds and fluidised beds • Thermal swing adsorption (TSA) and its variant electrical swing adsorption (ESA) • Pressure/vacuum swing adsorption (PSA/VSA) • Supercapacitive swing adsorption

For an adsorbent to be highly effective for carbon capture, some of the essential criteria (Lin *et al.* 2012; Samanta *et al.* 2012; Hedin *et al.* 2013) to be considered are:

- high CO_2 adsorption, working capacity and selectivity
- mechanical stability, with good structural attributes
    - optimum pore size for target species
    - suitable shape of material, such as structured adsorbents
    - minimum void space in the packing
    - adsorbents with high surface-area-to-volume ratio)
- able to operate under high volumetric flows and dust
- chemical stability towards flue gas impurities SOx, NOx and moisture
- optimum heat of adsorption (normally in the range of –25 to –50 kJ/mol for physisorption and –60 to –90 kJ/mol for chemisorption)
- ability to be regenerated with minimum energy penalty, effective heat integration and management
- minimum heat and mass transfer resistances with quick adsorption kinetics

- scalability and cost effectiveness including adsorbent precursor and its preparation.

Physisorption materials tend to have a higher CO_2 loading or working capacity (2-4 mol/kg; 9-17 wt %) compared to chemisorbents (1-2.5 mol/kg; 4-11 wt%) (ZEP 2017).

Depending on the type of interaction between the adsorbent material and CO_2, different process configurations can be applied to separate the CO_2. The actual configuration will depend on the specified CO_2 purity and recovery. In addition to the characteristics of the adsorbent, the adsorption process can also be optimized and adapted for a given material, to achieve improved performance (Nalaparaju *et al.* 2015). For example, the amount of CO_2 produced and energy penalty for a given adsorbent material will depend on parameters such as the cycle time, pressure and temperature of regeneration; the optimum regeneration conditions will also vary depending on the material properties of the sorbent (Berger and Bhown 2013).

Various adsorbents have been reported in the literature with their capture capacities and regeneration in a cyclic configuration. Carbon and zeolite-based adsorbents are generally considered superior to metal oxide and hydrotalcite adsorbents for moderate-temperature CO_2 capture applications, such as PCC, but for high temperature applications, such as steam methane reforming and water gas shift, the latter adsorbents types are preferred compared to carbon and zeolites (Ebner and Ritter 2009). The advantages and challenges of some of the adsorbent materials are listed in the Table 13.

Table 13 Advantages and challenges of solid sorbents (Bhown 2017)

Adsorbent	Advantages	Challenges
Activated Carbons	Robust, low cost	Low selectivity, high energy use
Zeolites	Abundant, tunable	Low H_2O tolerance
Carbonates	Can operate at high temperature	Low stability, high energy use
Amine Silicates	Low energy use, moisture tolerant	Low stability
Metal-organic frameworks	Large change in CO_2 uptake with small changes in pressure or temperature	Low stability, expensive, limited number of MOFs studied for regeneration processes, assessment under real flue gas conditions required

Fixed-bed and moving-bed sorbent systems

The type of contactor must be tailored to the sorbent's characteristics to maximise sorbent performance. The two main configurations for contacting flue gas with solid sorbents for CO_2 capture are fixed-bed and moving bed, with different configurations strongly influencing techno-economic performance (Samanta *et al.* 2012).

In simple fixed bed systems, the sorbents are held in a vessel with flue gas entering at one end and the CO_2-lean gas exiting at the other. During the process, only a small part of the sorbent actively adsorbs CO_2, while the other portion is either fully saturated, awaiting regeneration, or not yet contacted by the sorbate. Heat transfer requires careful attention in a fixed-bed design, as the heat of adsorption is propagated in localised mass transfer zones. Overheating of the sorbent should be avoided, as it reduces carrying capacity, or wastes liberated heat, therefore increasing the energy penalty for regeneration (Rackley 2017).

Moving-bed processes overcome these difficulties, since each section of the sorbent can be continuously moved from the adsorption bed for regeneration, while mass transfer between the adsorption and desorption zones provide an extra degree of freedom for overall heat management.

Fluidised beds are the most common form of moving bed adsorber and have more applications in many industrial processes, including power generation, combustion and gasification. Fluidised bed contactors are likely to be superior to fixed-bed adsorbers (Samanta *et al.* 2012). However, certain technical requirements need to be addressed, including the need for the sorbent particles to resist attrition, and for equipment to circulate sorbents and to remove attrition products.

An alternative form of moving bed that has also been proposed for carbon capture applications is the rotating packed bed (Gupta and Ghosh 2015). In this configuration, circular sorbent discs rotate between an adsorption chamber, where they are exposed to flue gases and a desorption chamber where the sorbent is regenerated under a pressure–temperature swing. Conceptual studies of this system, using activated carbon and zeolite 13X as sorbents and configured for PCC from a 500-MW power plant, indicated a significantly lower energy penalty and lower cost of CO_2 emission avoided than other capture technologies.

Adsorbent regeneration

After the adsorption step, the sorbents are regenerated by generally adopting temperature swing (TSA), pressure or vacuum swing (PSA/VSA), electrical swing (ESA) (variant of TSA, electrothermal desorption in which the sorbent is heated by joule heating), or as combination of these processes (Lee and Park 2015). The separation efficiency and product purity for TSA or PSA can be increased by applying a vacuum, resulting in a combined temperature vacuum swing adsorption (TVSA) or vacuum pressure swing adsorption process (VPSA).

As the bond strength (measured by the heat of sorption) between the sorbent surface and CO_2 increases, so does the energy needed to regenerate the sorbent. In TSA, the adsorbed CO_2 is released by increasing the system temperature using hot air or steam, supplied either as direct or indirect heating of the sorbents. In PSA, the gas components are captured at an elevated pressure, and the sorbents are regenerated by lowering the pressure. A rinse step is generally introduced to increase the purity of the strongly adsorbed component (CO_2) over the weakly adsorbed component (N_2); however, this dramatically increases the power consumption (Park *et al.* 2002).

VSA is similar to PSA, where the regeneration is conducted at reduced pressures, while adsorption occurs at ambient or near-ambient pressures. The CO_2 is at low pressure when recovered and needs to be compressed for storage. It would be possible to achieve high CO_2 purities (93%) from typical flue gas mixtures with 13% CO_2 at 40°C, with high recovery (>90%) and lower energy consumption (0.432 MJ/kg), but the specific energy consumption increases considerably if a purity above 95% is to be achieved. Given the large flue gas volumes from large point sources such as power plants, PSA and VSA are unlikely to be used (with a standard sorbent) as a stand-alone process for the capture of CO_2 (Chaffee *et al.* 2007; Hedin *et al.* 2013). However, they could be used as a pre-step before an absorption-driven process (Hedin *et al.* 2013), or when combusting fuel at somewhat elevated pressures in a pre-combustion route (Franco and Diaz 2009).

Factors affecting CO_2 recovery

CO_2 recovery follows the order as ESA < TSA < PSA < VSA < VTSA (Songolzadeh *et al.* 2014).

An advantage of PSA or VPSA processes is that their cycle time is at least an order of magnitude lower than that of TSA cycles (i.e. much higher productivity). By reducing the cycle times, smaller quantities of adsorbents can be used, which reduces the cost of separation. Reduced cycle time with rapid-TSA processes has been achieved with fluidised beds (Pirklbauer *et al.* 2017) and rotary wheel adsorbers (RWA) (Gibson *et al.* 2016), finned adsorbent beds (Mérel *et al.* 2006) and incorporating heat recovery using a heat pump (Miles *et al.* 1993).

The use of a pre-cooling step increases the adsorptive capacity of the sorbent and reduces the working capacity of the bed (Bonjour *et al.* 2002; Rackley 2017).

TSA-based processes can use low-grade waste heat input from the power plant to further reduce the energy penalty of an integrated CO_2 capture process. These processes also use a small purge to help the desorbed CO_2 to flow out of the bed. CO_2 purity generally increases with desorption temperature at a given purge, while it is more diluted when increasing the purge at constant desorption temperature. CO_2 recovery increases with the temperature and decreases when the purge increases.

Using a VTSA process could decrease the desorption temperature, but this requires a trade-off between heat and electrical energy consumption (Mérel *et al.* 2006).

In a VPSA cycle the recovery will depend on the vacuum pressure (0.15-0.2 bar) and requires a two-stage multicolumn configurations.

7.2.1 Sorbents in pre-combustion CO_2 capture

PSA or VPSA processes have been commercially applied in air separation (removing impurities from air) and H_2 production. They cannot be directly applied to CO_2 capture in power plants, because they require large flows with CO_2 as the more strongly adsorbed component, and the sorbent regeneration steps must release a concentrated stream of CO_2.

Two-bed VPSA has been demonstrated in the Air Product's SMR plant at Port Arthur (Texas, USA) capturing around 1 Mtpa of CO_2 from the shifted syngas, transported and used for enhanced oil recovery operations (USDOE 2012; Air Products 2013; Grande *et al.* 2017). This process uses a formulated metal-organic framework (UTSA-16) adsorbent in a packed bed to selectively capture CO_2 (17%) from steam-methane-reforming off-gases, achieving 90% CO_2 capture and 97% purity. However, many of the metal-organic frameworks synthesised are very expensive and their stability with respect to water vapour requires further improvement. From an energy-efficiency point of view, to be competitive with absorption, the CO_2 recovery target for PSA needs to be reduced from 90% to about 80% (Riboldi and Bolland 2016).

A potassium-carbonate promoted hydrotalcite-based material (K-MG30) (30 wt% Mg) was tested in the high-temperature sorption-enhanced water-gas shift process. In this process, the solid sorbent hydrotalcite material reacts with CO_2, shifting the water-gas shift equilibrium towards H_2. CO_2 is released in a concentrated form by a pressure swing and purging the bed with low-pressure steam (van Selow *et al.* 2011). The sorbent material performed better than the reference material from an earlier study (van Selow *et al.* 2009); under similar feed gas conditions (20% CO_2, 16% H_2O, balance N_2) it achieved superior mechanical stability after 1200 cycles, and had a greater cyclic capacity and a lower steam requirement for regeneration. With this material, CO_2 purity over 95% with CO_2 recoveries of 99% were obtained. However, the low delivery pressure of the CO_2 plus steam product mixture (~0.2 MPa) and the requirement for high-pressure CO_2 (~3.0 MPa) for the heavy reflux, reduced the overall energy efficiency of the process (Rackley 2017).

TDA Research Inc, used a mesoporous carbon modified with surface functional groups in a 0.1-MW_e pilot for CO_2 capture from IGCC power plants. An eight-bed PSA with 40% CO_2 feed concentration operated at 140-190 psig, at 200-250°C, obtaining a CO_2 capture efficiency of 90-97.3% and estimated cost of capture of under $40/tonne. Higher CO_2 capture was obtained with improvements in the cycle scheme and sorbent capacity but a higher pressure drop limited its performance (Alptekin et al. 2017).

CO_2CRC carried out a pilot-plant trial (0.37 kg/hr) with zeolite adsorbents (13X and 3A) for CO_2 capture from gasification syngas using VPSA operated at 120-200^{o}C and 7.2 bar. A maximum CO_2 purity of 98.2% and recovery of 87.7% was reported (Anderson *et al.* 2011). A trade-off between CO_2 removal and recovery was noticed, with improvement in adsorbent selectivity with additional product purge and pressure equalisation stages. Issues identified included the presence of heavy hydrocarbons and trace amounts of sulphur on the sorbent.

7.2.2 Solid sorbents in post-combustion CO_2 capture

More than 250 potential CO_2 adsorbents have been evaluated by ADA Environmental, who grouped them in four categories: supported amines, carbons, zeolites, and supported carbonates. Supported amine sorbents were selected for further investigation, because they met the 90% CO_2 capture criterion, had the lowest regeneration energy and required the least amount of material handling.

Based on a laboratory-scale 1 kW plant with supported amine sorbent in a circulating fluidised bed, ADA Environmental conducted PCC trials using a 1 MW_e pilot plant (Krutka *et al.* 2013). They considered several different reactors for gas-solid contacting for CO_2 adsorption and thermal swing regeneration, including fixed beds, transport reactors, moving beds, trickle down reactors, and staged fluidised beds. The staged fluidised adsorber and a fluidised bed regenerator operating in the bubbling fluidised bed regime provided the best configurations. The fluidised-bed reactor had the most efficient heat and mass transfer, and therefore provided the optimal configuration for effective CO_2 capture. The results met the United States Department of Energy requirements of 90% capture at less than $40 per tonne. Heat recovery was also integrated, with the use of a cross heat exchanger to recover sensible heat from the sorbent leaving the regenerator and transfer this to the incoming sorbent.

Structured sorbent packings, such as monoliths, have significant advantages over packed beds of sorbents in VTSA for PCC (Thiruvenkatachari *et al.* 2009). A prototype carbon-fibre composite solid-sorbent PCC unit was trialled at a coal-fired power station using actual flue gas (CO_2 at 9.9-13%) (Thiruvenkatachari *et al.* 2015). More than 200 test cycles of adsorption and combined thermal and vacuum swing regeneration were performed to evaluate sorbent performance and stability. Under the study conditions, CO_2 adsorption efficiency was consistently >98% with and without flue gas pre-treatment. Adsorption performance of the sorbents was maintained even after more than 200 tests, demonstrating for the first time that the carbon-fibre composite solid sorbents were very stable under real flue gas conditions without any noticeable impact of SO_2 and NO_x on performance.

The CO_2 desorption efficiency of the sorbent material using combined heat and vacuum swing was 90- 95%.

Inventys uses the VeloxoTherm process, which can capture CO_2 for 15 US$/t (Inventys 2017). The technology involves an intensified TSA process with a structured adsorbent and steam regeneration in a rotating adsorbent wheel. The ATMI/SRI BrightBlack microporous carbon was recently tested at a coal-fired steam production facility operated by the University of Toledo in Ohio, USA (Boot-Handford *et al.* 2014). The material exceeded the US DoE targets of >90% CO_2 capture with >90% CO_2 purity during tests with 200 standard L/min of flue gas. The column operated for ~7000 adsorption–regeneration cycles with no loss in process or adsorbent performance, and no signs of adsorbent degradation.

RTI International is developing an advanced solid sorbent, first developed at Pennsylvania State University, based on a CO_2-philic poly-amine (i.e. PEI) loaded on a high surface area support material, such as silica (Nelson *et al.* 2017). Multiple bench-scale tests have investigated diverse CO_2 emission sources, such as coal-fired power plants, natural gas combined cycles and cement plants. To adequately manage the heat generated by a solid sorbent CO_2 chemisorption reaction, a fluidised-bed reactor design was adopted to achieve high overall heat transfer coefficients. RTI also used simulated flue gas in a 100 hours test campaign, in which varying the solid-to-gas ratio enabled CO_2 capture rates of 90% ±2%. This demonstrated that the PEI-sorbent is fully regenerable in a continuous-flow, circulating system.

7.2.3 Chemical looping

In chemical looping combustion (CLC), similar to the fluidised-bed configuration, an oxygen-carrying sorbent is circulated between the separate reactors in which chemical adsorption and desorption reactions take place. A metal oxide sorbent carries oxygen (oxygen carrier) to the fuel reactor, where combustion takes place. The reduced oxygen carrier is then conveyed to an air reactor where it is regenerated (oxidised in air), thus closing the chemical loop. Chemical looping combustion is a variant of oxyfuel.

Suitable oxygen carrier materials for CLC are transition metal oxides such as nickel (Ni), copper (Cu), cobalt (Co), iron (Fe), and manganese (Mn). Recent studies have investigated combined metal oxides, on low-cost materials for use with solid fuels, and on materials releasing oxygen (Jing Li 2017). The fuel could be gaseous fuels (syngas, natural gas, propane), or solid fuels (coal, biomass, coke) or liquid fuels (diesel, bitumen, and heavy oils).

Current CLC R&D efforts are focused on (ZEP 2017):

- developing and refining oxygen carriers with sufficient oxygen capacity and durability to withstand the harsh environments at an acceptable cost
- developing effective and sustainable solids circulation and separation techniques
- improving reactor design to support different fuel and oxygen carrier choices
- effective heat recovery and integration
- overall system design and optimization
- reduction of gas leakage between oxidation and reduction reactors (Jing Li 2017).

7.2.4 Calcium looping

Calcium looping is a high temperature CO_2 removal technology in which CaO reacts with CO_2 in flue gas streams, forming $CaCO_3$ (carbonation). The $CaCO_3$ is sent to a separate reactor where it is regenerated (calcination), producing a concentrated CO_2 stream suitable for transport and geological storage (Abanades *et al.* 2004). CO_2 capture with CaO is usually coupled with oxy-fired combustion to regenerate the CaO and release of high purity CO_2 (Abanades *et al.* 2015). Operation of a pilot-scale fluidised-bed carbonator on a synthetic flue gas (15 vol% CO_2 in air) showed CO_2 capture rates of around 90% at 650^{o}C. However, efficiency decayed with operation (Abanades *et al.* 2004). Increasing the capture rate further is limited by equilibrium limitations.

Some of the key issues for calcium looping systems include, sorbent integrity, attrition, minimising O_2 consumption in the calciner, sorbent capacity degradation with repeated regeneration. Typical losses in capacity are 50% after 5 cycles and 80% after 20-40 cycles (Rackley 2010). Sorbents derived from dolomite and huntite are more durable under repeated calcining due to the presence of MgO in the calcined product, which remains inert in the carbonation reaction at high temperature (Rackley 2010)

Calcium looping technology has been tested in several pilot plant trials of between 0.01–2 MW_e (Abanades *et al.* 2005; Alonso *et al.* 2010; Rodríguez *et al.* 2011; Endesa 2012; Kremer *et al.* 2013; Ströhle *et al.* 2014; Duelli *et al.* 2015):

- The Caoling project is a 1.7 MW plant that achieved a CO_2 capture rate of over 90% from a flue gas slip stream from La Pereda power plant, Spain (Endesa 2012; Fred Vitse 2016).
- A 3 MW prototype chemical looping- gasification facility is being developed by GE Power (Fred Vitse 2016).
- INCAR-CSIC designed and operated a 30 kWth test facility made up of two interconnected circulating fluidised-bed reactors (0.1m ID) and reported CO_2 capture efficiencies between 70 and 97% under realistic flue gas (post-combustion) conditions in the carbonator reactor. This reactor functioned as an effective adsorber for CO_2 as long as there was a sufficient bed inventory and solid circulation rate, even with highly deactivated calcium oxide (Rodríguez *et al.* 2011). This test facility was also used to test the principle of low-temperature combustion of biomass (700 ^{o}C) for in situ CO_2 capture (Alonso *et al.* 2011).
- Ohio State University developed a 120 kW plant to perform the carbonation–calcination reaction process, which consists of a calcium-looping system with an intermediate hydration stage to prevent the decay in sorbent reactivity over multiple carbonation–calcination cycles (Wang *et al.* 2012). The pilot test rig involves an entrained bed carbonator, a rotary kiln calciner and a bubbling fluidised-bed hydrator. The process is highly effective and efficient in removing >90% of CO_2 and almost 100% of SO_2 under realistic conditions.
- ITRI has developed its High-Efficiency Calcium Looping Technology (HECLOT) and collaborated with Taiwan Cement Corp., for a 50-MW demonstration plant for CO_2 capture. HECLOT reduced the energy penalty to less than 20% and achieve a CO_2 capture rate of >90% at a cost of less than US$30/tonne of CO_2 (ITRI 2017).
- In situ capture of CO_2 with CaO was evaluated in a 300 kWth pilot plant CFB combustor utilising wood pellets (Alonso *et al.* 2014). This concept relies on the high reactivity of

biomass as a fuel, allowing combustion in air at temperatures around 700°C. Regeneration of the CaO would require a separate oxy-fired calciner. They were able to achieve CO_2 capture rates in the range of 70-95%.

7.3 Membranes

A membrane is a thin barrier that allows selective passage of different species (Abanades *et al.* 2015). The barrier material can be organic (polymeric, carbon) or inorganic (ceramic, metal). It is usually very thin and requires a (porous) support material to give it structural strength. Typically, the partial pressure difference of a species on different sides of the membrane provides the driving force for separation.

7.3.1 Membranes for post-combustion CO_2 capture

Due to the low partial pressure of CO_2 in combustion flue gas streams, CO_2 separation via membranes is challenging in this application. Nevertheless, membrane systems for CO_2 capture from combustion flue gas streams have been developed and use feed compression and/or permeate vacuum to provide the driving force for separation. The incoming combustion air can be used as a sweep gas, increasing CO_2 concentration in the flue gas (Merkel et al 2010). This concept has been pioneered by Membrane Technology Research and is able to provide 90% CO_2 capture with a product of 95% CO_2-purity (Figure 20).

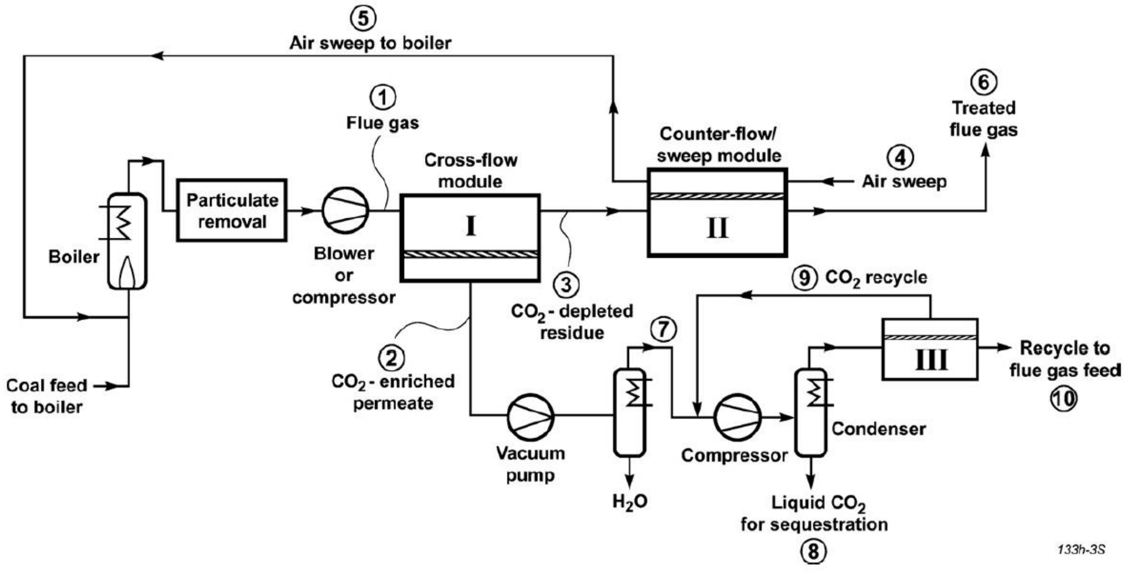

Figure 20 Two-step counter-flow sweep membrane process for CO_2 capture in a coal-fired power plant (Merkel et al. 2010)

Membrane Technology Research have evaluated their Polaris membranes on real coal flue gases at the National Carbon Capture Centre (NCCC), capturing 1 tonne CO_2/day. The membranes were able to capture 83-91% of the flue gas CO_2 over 1300 h of operation (Merkel *et al.* 2010). Air dilution was used to simulate capture from a NGCC. Though not specifically designed for this process, they were able to capture 80% of the CO_2. In total 11,000 hours of operation have been achieved at NCCC (Hofmann *et al.* 2017).

Maas et al. (2016) showed that it is also possible to achieve 90% CO_2 capture at 95% CO_2-purity using a membrane cascade system shown in Figure 21.

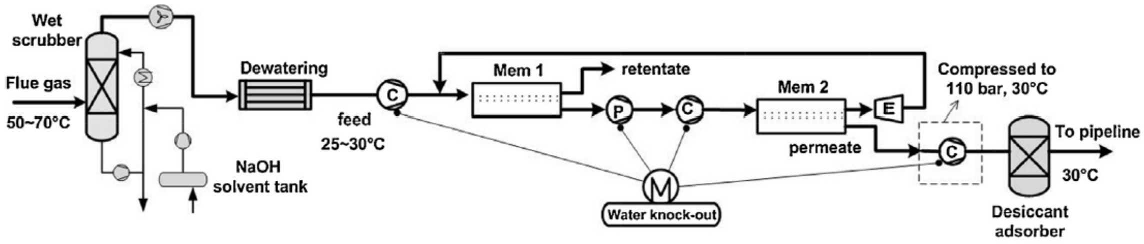

Figure 21 Membrane cascade system for CO_2 capture in a coal-fired power plant (Maas et al. 2016)

The application of membranes for PCC does not lend itself to capture rates above 90%, as this would require either deeper vacuum or higher compression rates to provide the driving force for separation. Roussanaly and Anantharaman (2017) indicate that for typical flue gas concentrations in coal-fired power plants, the economic optimum capture rate will be at capture rates lower than 90%.

7.3.2 Membranes for pre-combustion CO_2 capture

Pre-combustion CO_2 capture is based on the ultimate conversion of fuel into a pressurised CO_2/H_2 mixture at high temperatures. There are performance and economic benefits if the gas separation can be carried out at temperatures close to the temperatures for fuel conversion and water-gas shift reactions. High temperature, H_2-selective membranes are very suitable for pre-combustion CO_2 capture in both coal and gas-fired power stations. These are either Pd-based membranes or ceramic membranes that can selectively transport hydrogen over other gases, and have potential for application in IGCC power plants.

This membrane technology also combines the conversion of fuel into H_2 for large-scale power production with CO_2 capture. The process leaves concentrated CO_2 at high pressure, reducing the compression energy needed for transport and storage. Key challenges are related to the further upscaling of the membrane manufacture, and stability under operating conditions and in the presence of contaminants. Key characteristics required are sufficient permeability, selectivity, robustness and durability in relevant environments. Pd-based membranes have limited stability towards sulphur but can provide absolute selectivity. Alloying Pd/Ag membranes with metals such as gold and ruthenium can improve membrane stability under mild H_2S conditions (1-5 ppm).

Zeolite membrane reactors are being studied for the water-gas shift reaction of coal gasification gas for hydrogen production and CO_2 capture (Lin 2016). A CO_2 capture rate of 90% and a CO_2-purity of >95% are achieved by both type of membranes. Given that feed-gas streams are at pressure, it seems likely that capture rates can be increased more easily in the case of membrane based pre-combustion CO_2 capture.

7.3.3 Membranes for oxyfuel

High-temperature, ion-transport membranes have been under development for some time. Their ultimate goal is to transfer oxygen from the air selectively to the fuel at high temperatures, resulting in a product gas stream of CO_2 and H_2O. Oxygen is transported through the membrane in its ionic form; this type of transport is extremely selective. It is therefore well suited to provide high CO_2 capture rates, as nitrogen does not transfer through the membrane. Air Products is one of the leading developers in this field, with flat, wafer-based membrane module design. These systems can also be used for stand-alone oxygen production, with a 14% reduction in oxygen cost compared to cryogenic air separation anticipated (Lockwood 2014).

7.4 Refrigeration

Refrigeration-based CO_2 capture involves cooling the flue gas stream to the point where the CO_2 forms a liquid or solid that can be separated from the gas.

Berstad et al. (2013) reviewed low-temperature CO_2 separation processes for combustion flue gases. They note that the flue gas CO_2 concentration has a large effect on the separation and compression work required, and on the achievable CO_2 capture rate for separation of liquid CO_2. For typical combustion flue gases with CO_2 concentrations in the range of 4-15 vol% (dependent on fuel type), CO_2 capture rates below 50% are expected. However, if the CO_2 is frozen out, the vapour-solid equilibria apply and pure CO_2 can be recovered by defrosting (Pan *et al.* 2013). With these processes, 100% capture of the CO_2 from a flue gas is theoretically possible (Berstad *et al.* 2013; Jensen *et al.* 2015).

In the case of pre-combustion capture, the higher CO_2 partial pressure of most shifted synthesis gases makes CO_2 removal possible via partial condensation. Berstad et al (2013) used phase equilibrium calculations for a binary CO_2/H_2 mixture to determine the achievable CO_2 capture ratio via partial condensation. They showed that the achievable CO_2 capture rate depends on the CO_2 partial pressure and temperature. For CO_2 concentrations above 50%, and pressures above 50 bar, 85-90% capture of the CO_2 is theoretically possible, with higher CO_2 capture rates limited by phase equilibria. They suggest that a CO_2 capture ratio of 85% as a practical limit for CO_2 capture by partial condensation and phase separation of synthesis gas.

7.5 Synthesis of literature results for CO_2 capture technologies

The capture of CO_2 from flue gases or other power plant gas streams, such as CO_2/H_2 or CO_2/O_2 mixtures, requires a separation process that can use physical or chemical means. Physical means include a phase change through temperature change, a difference in solubility or diffusion through materials, while chemical means could include chemical reactions with solid or liquid agents.

Separation processes have the following characteristics:

- Selectivity – the propensity of the process or separation agent to remove the target component uniquely from the feed stream
- Product purity – a feed stream can be split into a range of products that may need to adhere to certain purity requirements.

- Product recovery – the amount of useful product that may be recovered from a feed gas stream.

In the context of increasing the rate of CO_2 capture in power plants, the aim of a separation process is to increase product recovery while maintaining the product purity. The latter is normally set at 95% CO_2 with possible constraints on the concentration of certain impurities, like oxygen. The selectivity is indicative of the effectiveness of the separation task. The literature review indicates that most studies have focused on the common capture rate of 90%, while only a few have considered higher CO_2 capture rates.

An overview of the suitability of different capture technologies is provided in Table 14, where a 99% CO_2 capture rate is taken to be representative of high capture. Higher capture rates are not only determined by the capture agent or principle, but also by the process operation.

Table 14 Overview of suitability for achievement of commonly used (90%) and high (99%) CO_2 capture rate for different capture technologies

Capture technology	90% CO_2 capture	99% CO_2 capture	Comments
Chemical absorption	+	+	Increased costs Higher energy consumption
Physical absorption	+	+	Pressurised gas streams Deeper regeneration
Solid sorbent - chemical	+	+	Process design optimisation Steam stripping; vacuum
Solid sorbents - physical	+	+/-	Trade off with CO_2-purity Process design optimisation
Chemical looping	+	+	Selective process Avoidance of leakage between reactors
Polymeric membranes	+	-	Bulk separation works best with pressurised gas streams Trade-off with CO_2 purity High compression/low vacuum needed
Metal membranes (H_2)	+	+	Used with pressurised gas streams High selectivity
Ion transport membranes (O_2)	+	+	High selectivity
Ceramic membranes	+	+	Used with pressurised gas streams
Refrigeration	+	+/-	Higher capture rates achievable with CO_2-solid formation; purity issues with liquid formation

(+) achievable, (-) not achievable

Polymeric membrane technology is the technology which lends itself least for higher capture rates. Other more selective membrane technology will be able to achieve higher capture rates.

For solid sorbent technology there is likely to be a trade-off with the CO_2-purity, i.e. at high capture rate the purity will decrease. A highly selective solid sorbent, e.g. based on a chemical interaction with the substrate, will be less impacted by this issue. This observation can be translated to the suite of chemical looping processes as they share some of the same technological principles.

Refrigeration processes are also able to work at higher CO_2 capture rates if the cooling leads to the formation of solids rather than liquids.

In general one can conclude that the suite of capture technologies (agents and processes) is well amenable to higher capture rates. An overall assessment of the CO_2 capture rate for the emerging capture processes would be needed to determine the techno-economic optimum.

One should also bear in mind that hybrid options, such as cost-effective combinations of different CO_2 capture technologies, can also be applied.

8 Impact of increasing CO_2 capture rates for post-combustion capture

In this section, we outline the considerations for increasing CO_2 capture rates in post-combustion capture (PCC), including the minimum energy requirements for both CO_2 capture generally and then more specifically for amine-based capture. We then discuss the anticipated impacts from increasing CO_2 capture rate. Two case studies are included: PCC plants optimised for CO_2 capture, integrated with an ultra-supercritical pulverised coal-fired power plant or integrated with a natural-gas-fired combined cycle.

8.1 Minimum energy requirements for CO_2 capture

The minimum energy requirements for the separation of CO_2 from a flue gas can be determined from basic thermodynamics assuming the mixture behaves like an ideal gas. For the complete separation of a binary mixture into its pure components, the minimum energy requirement can be determined from the following equation (Feron 2010):

$$W = -NRT \cdot \{x \cdot \ln(x) + (1-x) \cdot \ln(1-x)\} \tag{1}$$

where

W : Minimum energy requirement [J]

N : Total number of moles in mixture [mol]

R : Gas constant [J/mol·K]

T : Absolute temperature [K]

x : CO_2 mole fraction [-]

The specific energy requirement can be obtained by dividing Equation 1 by the amount of desired product i.e. $x \cdot N$. Equation 1 represents the mixing energy which is released when two pure ideal gases are mixed. In a reversible process, this amount of energy has to be expended to separate the components back into the original pure gases. It can be understood as the compression energy needed to raise the individual partial pressure to the ambient pressure. Equation 2 is based on complete recovery of both components, which is not a practical situation when aiming for a certain recovery.

Amel'kin et al. (2001) have provided the more general equations where the separation is incomplete, i.e. where the binary mixture is separated into two streams, which are still mixtures of the original components in the binary mixture. This is a more realistic representation of a CO_2 capture process. The calculation of minimum energy requirement can be interpreted as the energy needed for complete separation into the pure products from which the mixing energy to produce the two product streams with different concentration is subtracted. In a typical PCC process based on absorption technology, the flue gas is separated into a pure CO_2 product and a reduced flue gas stream more diluted in CO_2. The CO_2 capture rate is therefore an important parameter and particularly relevant in the context of this study.

Equation 2 describes the energy requirement per mole CO_2 removed (w) as a function of the CO_2 capture fraction (f) which is equivalent to the capture rate divided by 100.

$$w = -RT \cdot \{\ln((1-f)x/(1-fx)) + \ln(1-fx)/fx - \ln(1-f)/f\} \qquad (2)$$

Figure 22 shows the specific minimum energy requirement for CO_2 capture as a function of the capture rate for several values of the CO_2 inlet concentration representing the exhaust gas of a coal-fired power station (12%), a natural gas combined cycle (3.5%) and a cement plant (20%). Also CO_2 capture from air is given as a reference case. The evaluation was carried out at 50 °C.

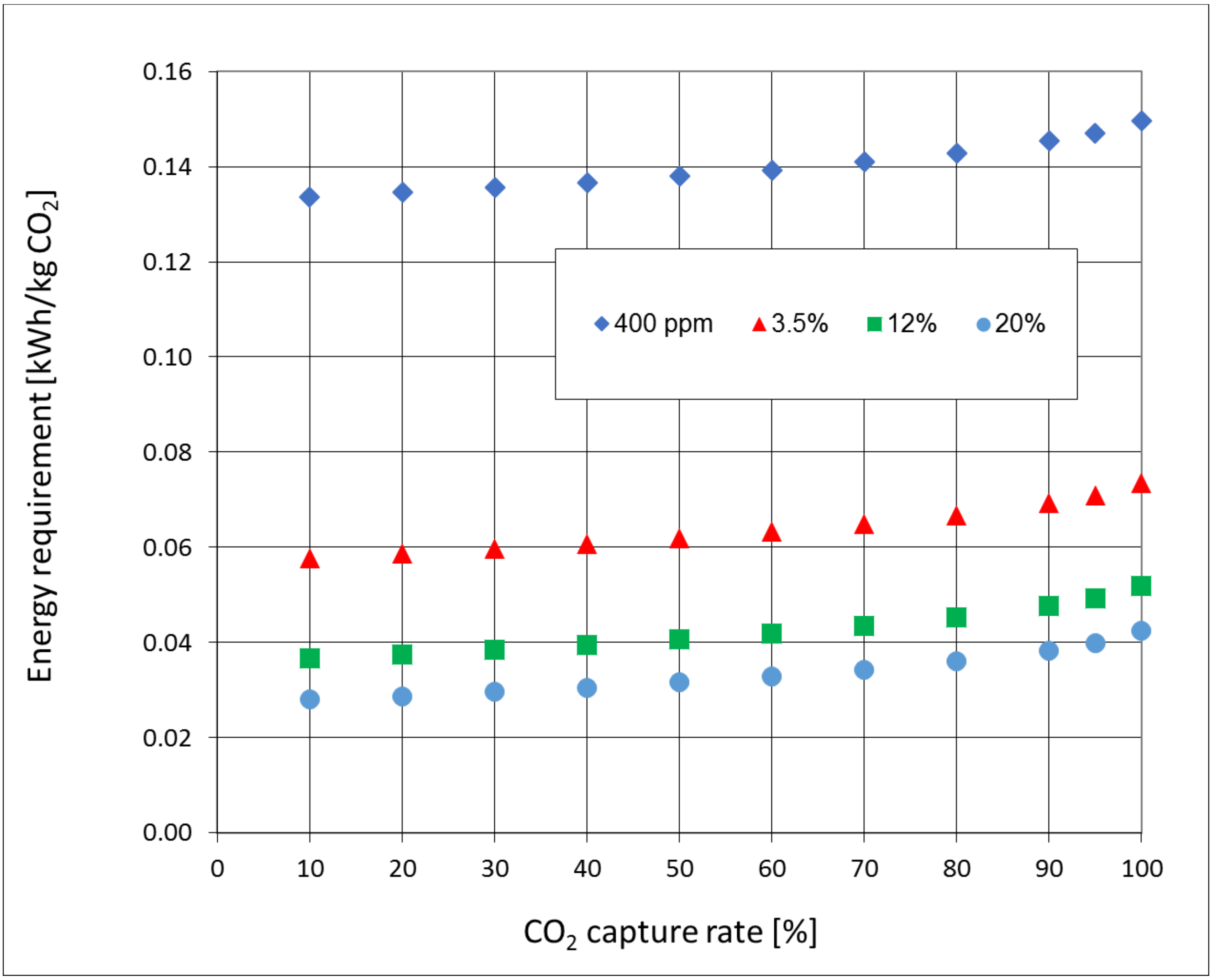

Figure 22 Minimum energy requirement for CO_2-separation as a function of CO_2 capture rate for different concentrations of CO_2 (T = 50°C)

Comparison of the minimum energy requirement at 90% and 100% indicates that according to theory, the additional energy required to achieve full capture is between 6 and 11%, which is a relatively minor increase. However, in practical separation processes, there is not always a direct link between the capture process energy requirement and the theoretical minimum energy requirement.

8.2 Amine-based CO_2 capture

Current PCC processes are predominantly based on chemical absorption using aqueous amine solutions (Rochelle 2009). These processes can selectively remove CO_2 to the low levels required by product gas specifications in liquefied natural gas or as required for power-plant flue gas applications. Their applicability is well proven for natural gas treatment, and more recently also for removing CO_2 in coal and gas-fired power plants to mitigate greenhouse gas emissions. Many, if not all, power-plant technology suppliers have started in-house PCC development programs, running pilot-plant projects at power plants to evaluate performance under realistic operating conditions.

In an amine-based PCC process (Figure 23), the flue gas is first cooled and/or pre-treated to reach a temperature level beneficial for the chemical absorption and to remove components, such as SO_2, that might reduce capture effectiveness. The flue gas is then directed to the absorber, in which it is contacted with the absorption liquid. CO_2 selectively absorbs into the aqueous solution and reacts with the amine compounds contained in the absorption liquid. The resulting CO_2-rich solution is then fed to the desorber via the lean/rich heat exchanger.

At the prevailing desorber temperatures, CO_2 is released as a wet gas stream. Most of the water vapour is subsequently recovered in the condenser as liquid water, and returned to the desorber or another point in the absorption liquid circuit to maintain the plant’s water balance. The CO_2 product then goes to the compression stages to prepare for transportation and/or geological storage. The regenerated, CO_2-lean solution leaves the desorber at the bottom and is pumped to the absorber top via the lean/rich heat exchanger and the trim cooler.

In PCC applications the gas leaving the CO_2 absorption section will flow through one or more washing stages to recover amines present in droplets or as vapour in the treated gas. This will ensure emissions to the atmosphere are kept well within the regulatory and economic limits.

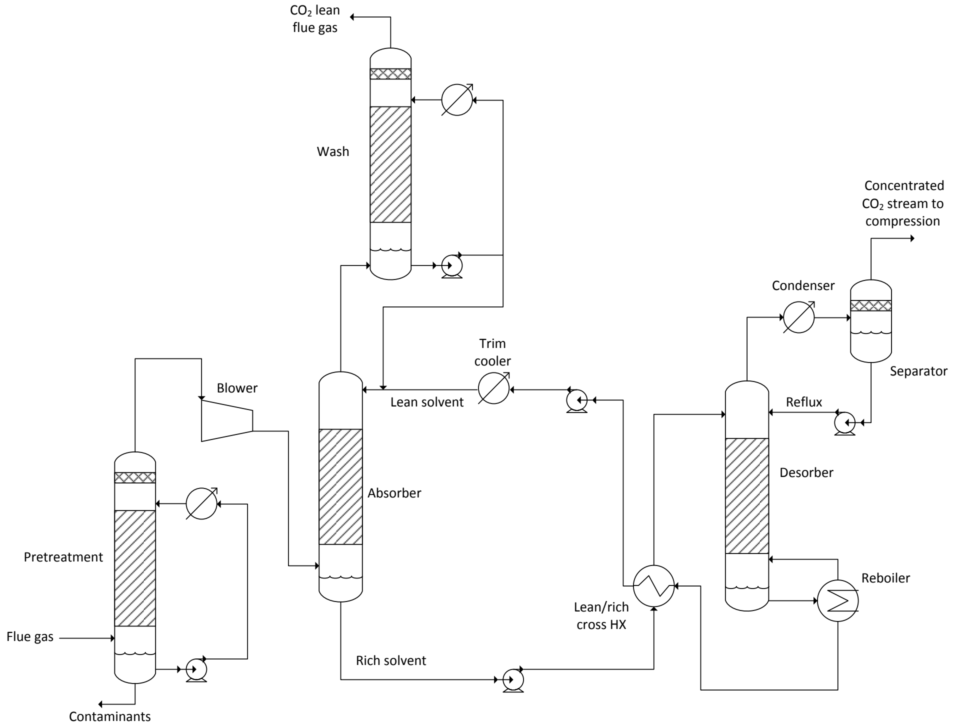

Figure 23 Amine-based CO_2 capture process flow diagram

8.3 Energy requirements for amine-based post-combustion CO_2 capture

The overall energy requirements for CO_2 separation and compression to the required transportation or geological reservoir pressure form a major barrier to commercial deployment. The energy requirement has four major components, as described in the following sections.

8.3.1 Thermal energy for regeneration of the absorption liquid

Absorption liquid regeneration is normally affected by the provision of thermal energy to the solution through a reboiler at the desorber bottom (Figure 23). This will result in an upward flowing vapour stream, which at the desorber bottom mainly consists of steam.

Acting as an effective heat-transfer medium, steam will condense into the absorption liquid flowing downward, thus providing the thermal energy required for release of CO_2 and for the heating of the absorption liquid towards the desorber bottom. Steam also acts as a stripping medium, keeping the CO_2 partial pressure low to maintain the driving force for desorption.

The thermal energy required for the desorption process has three main components:

- the enthalpy required to reverse the reaction between CO_2 and the amine, followed by release from the absorption liquid
- the thermal energy required for raising the temperature from the exit temperature at the hot end of the lean/rich heat exchanger to the desorber bottom temperature
- the evaporation enthalpy for the stripping steam, which leaves the desorber together with the CO_2

The thermal energy can be provided through steam extraction from the host power plant. This steam is then not available for generating electricity, resulting in a reduction of the power plant output.

8.3.2 Electrical energy for the transport of flue gas through the system

The flue gases need to be transported through the pretreatment, CO_2 absorber and wash section(s). This results in a pressure drop, which needs to be overcome by the installation of additional fan(s). In case of air-cooled processes, the electrical energy requirement for the cooling process fans also needs to be taken into account.

8.3.3 Electrical energy for the liquid transfer through the system

The absorption liquid will need to be transported to the top of the absorber and desorber. The resulting pumping energy requirements therefore have to be considered, as well as the pressure drop in the piping system. In the case of water-cooled processes, the electrical energy requirements for the cooling processes also needs to be taken into account.

8.3.4 Electrical energy for compressing the CO_2 product

The CO_2 product from the capture process needs to be compressed to pipeline transportation pressure or injection pressure. In some applications, liquefaction might be preferred.

8.3.5 Reducing capture energy requirement

Reducing the capture energy requirement will require an integrated approach, involving the following areas:

- the amine-based capture agents, whose characteristics will lock-in minimum energy requirements through the CO_2 reaction enthalpy,
- the process design necessary to make optimum use of these capture agents, and in particular proper heat management within the process,
- the equipment design to optimise the process operations, which will determine the effectiveness of the overall process, e.g. through the determination of the heat and mass transfer areas in the chosen equipment,
- the integration with the power plant providing the flue gas and other interfaces with the external environment, which will determine the impact on the power plant output.

8.4 Anticipated impacts from higher CO_2 capture rates

Raising the level of CO_2 capture has consequences for the capture process, that will affect performance parameters, such as reboiler duty, liquid flow rates, equipment sizes (particularly for the contactors), and ultimately, capital costs and operational costs. The three most important factors – absorber column size, reboiler duty and electrical energy consumption – are discussed below.

8.4.1 Absorber column size

The absorber column size depends on the gas-liquid contact area needed for effective CO_2-transfer from the gas phase to the liquid phase. The gas-liquid contact area is determined by flue gas flow rate, the mass-transfer coefficient and driving force for CO_2-transfer to the absorption liquid.

In a chemical absorption process, both the mass-transfer coefficient and driving force will vary over the column height as the amine reacts with the CO_2 present in the flue gas. The detailed impact of an increase in the capture rate requires a dedicated absorber model taking into account these and other factors such the hydraulic design.

A simple estimate of the impact of increasing capture rate on the gas-liquid contact area requirement can be made if one neglects the equilibrium pressure of CO_2 in the loaded solution. In that case, the area will vary proportionally to $\ln(C_{in}/C_{out})$, where C refers to the CO_2 concentration in the flue gas, $_{in}$ is at the inlet and $_{out}$ is the outlet. This factor can be easily determined as a function of capture rate and is shown in Figure 24 normalised to 90% CO_2 capture.

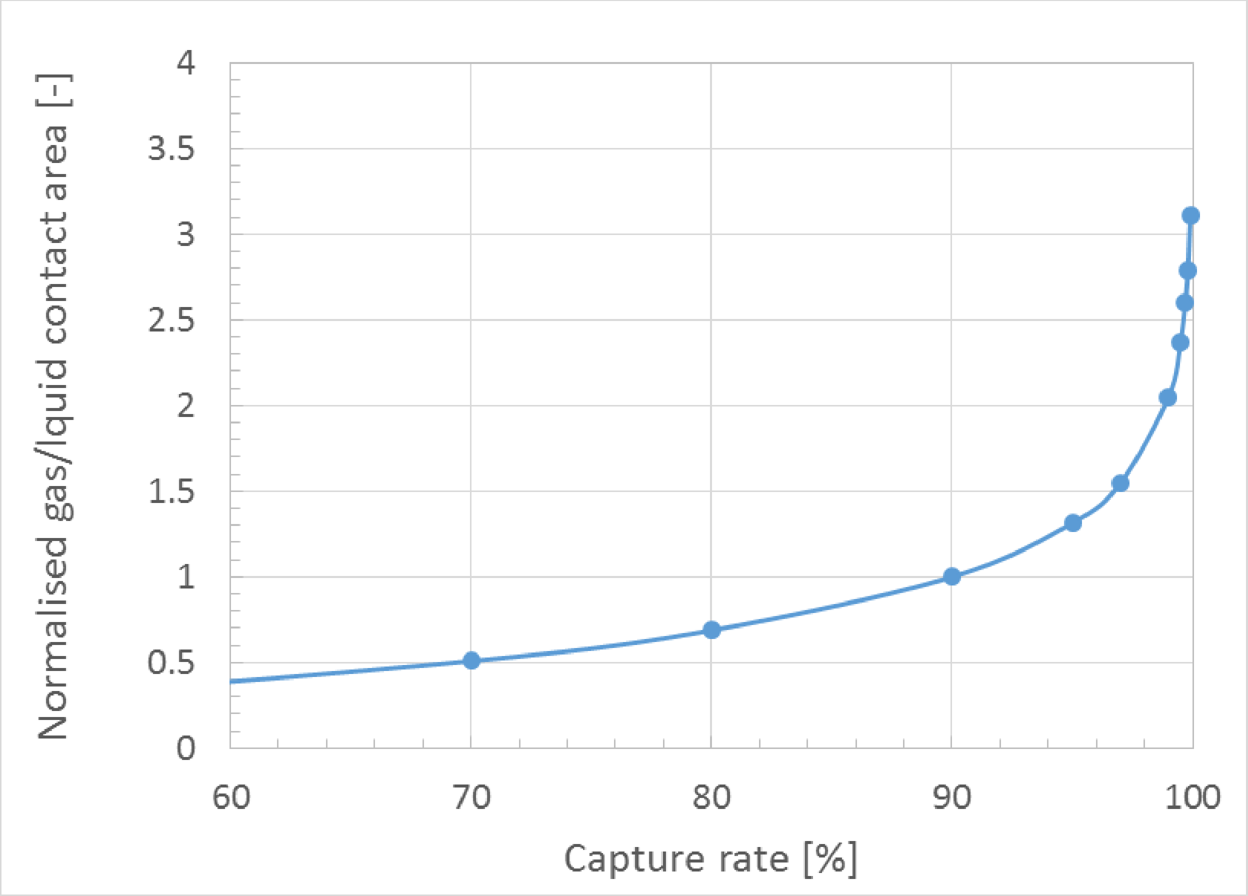

Figure 24 Gas liquid contact area requirement as a function of CO_2 capture rate normalised to 90% CO_2 capture

Figure 24 indicates that increasing the capture rate from 90% to 99% is likely to double the area requirement for the CO_2-absorber. As a measure for absorber height and cost this will have a sizeable impact on the overall capital cost and most likely also lead to higher pressure drop in the absorber.

8.4.2 Regeneration of absorption liquids

Higher capture rates are typically enabled by leaner absorption liquids, which provide the necessary lower equilibrium pressure for CO_2-transfer to occur at the lower outlet concentrations. Achieving a leaner absorption liquid is normally obtained at the expense of a higher specific reboiler duty, as more steam is needed to strip the CO_2 from the amine solution. Figure 25 shows the resulting outlet CO_2 concentrations as a function of the CO_2 capture rate at representative inlet concentration levels for a coal-fired power station (13%) and natural gas-fired combined cycle (3.5%). Also shown is the ambient concentration level of 400 ppm: in some cases the outlet concentrations are lower than the ambient concentration level. For a gas-fired combined cycle a lower level than ambient is already achieved at 99.1% CO_2 capture, whereas for a coal-fired power station the CO_2 capture needs to be around 99.7%.

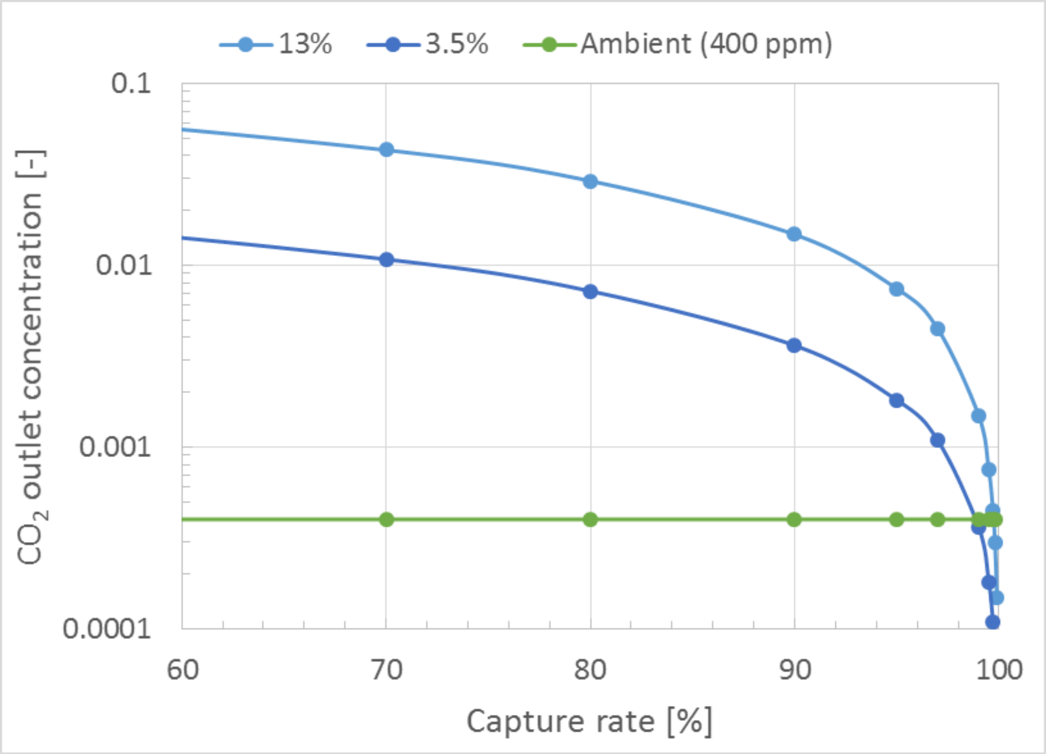

Figure 25 Outlet CO_2 concentration (volume fraction) for inlet flue gases representative of coal and natural gas-fired combined cycle

Experimentally derived literature data (Jou *et al.* 1995) on the CO_2 equilibrium pressure over a 30% monoethanolamine (MEA) solution have been used to better understand the practical possibility of reaching lower CO_2 concentration at the outlet of the absorber. The equilibrium concentrations are shown in Figure 26 at three different temperatures as a function of CO_2-loading. The ambient CO_2-concentration is shown for reference.

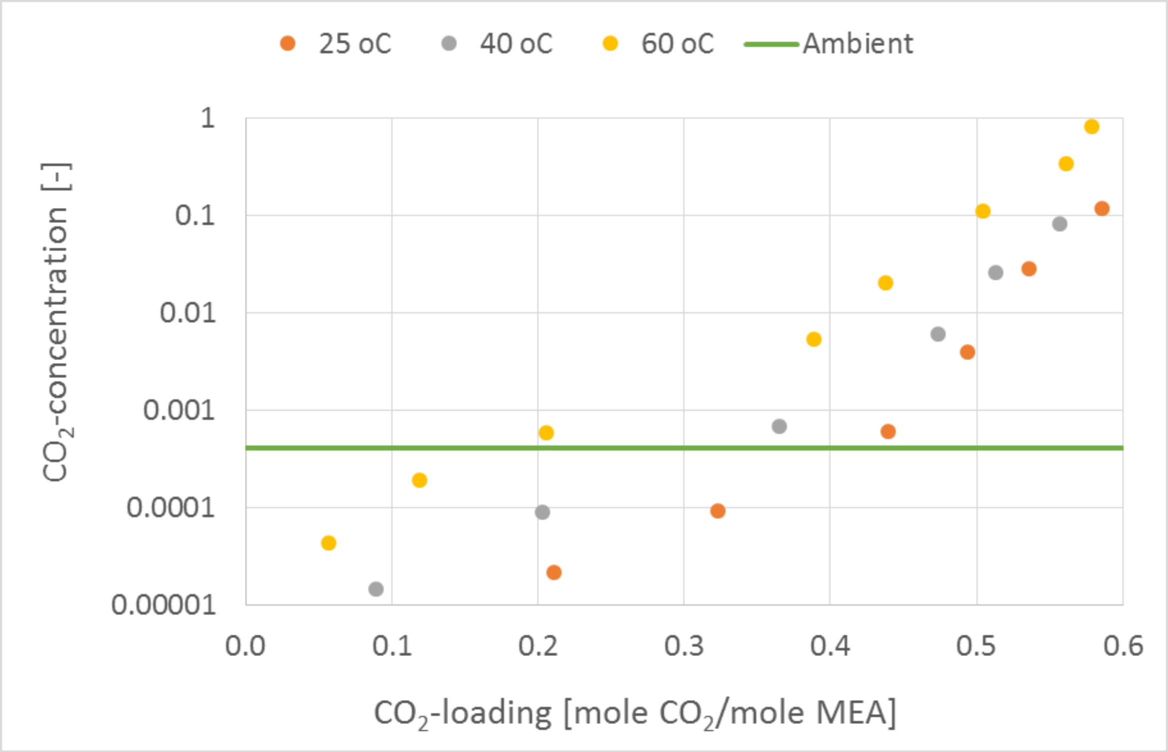

Figure 26 CO_2 equilibrium concentration (volume fraction) over a 30% monoethanolamine (MEA) solution at 1 bar total pressure

The CO_2 equilibrium pressure is a strong function of both temperature and CO_2 loading. The lean loading for an MEA-based PCC process is normally in the range 0.15-0.25 mole CO_2/mole amine, providing an equilibrium pressure that is even lower than the ambient CO_2 partial pressure at 40 °C, the typical lean liquid temperature at the inlet of the absorber.

At 90% CO_2 capture, the outlet concentration from a coal or gas-fired power station will be in the range 0.5-2% (CO_2 concentration = 0.005-0.02 in Figure 26) and there is therefore considerable driving force for the absorption process. This means that depth of regeneration in the standard amine process is sufficient to enable a large capture rate. Hence it is anticipated here that the reboiler duty might not change dramatically as a result of the increased capture rate. In addition, increased desorber temperatures do not seem necessary, because the depth of regeneration is sufficient.

8.4.3 Electrical energy consumption

As described in Section 8.3 electrical energy is used for the transport and compression of gases and liquids. As the column sizes are expected to increase, it is likely that the pressure drop over the columns is likely to increase as well, although there might be a trade-off between column diameter and height to minimise this effect.

An increase in the rich loading is unlikely, because this is largely determined by the inlet CO_2-concentration with a maximum loading of 0.5 mole CO_2/mole amine, as the typical value for MEA. This is unchanged by the level of CO_2 capture. As the lean loading will not undergo major changes, the change in the amount of liquid transfer is determined by the additional CO_2 capture, which is 11% at most. There might be some additional pressure because of an increase in absorber height.

The increased liquid flow rate will also lead to larger heat-transfer equipment, and hence increased capital cost.

The total compression energy requirement will increase in proportion to the amount of CO_2 captured. As compression conditions do not change with changes in capture rate the specific compression energy consumption will be unaltered.

On balance, increasing capture rates are expected to only marginally increase the specific electricity consumption.

8.5 Post-combustion plants optimised for CO_2 capture

Initial PCC process simulations using Protreat® were carried out for a standard amine-based (30% MEA) PCC plant that was designed for 90% capture from a coal-fired power plant (Ramezan *et al.* 2007). Increasing the capture rate for this plant indicated a significant increase in reboiler duty as well as flooding issues in the desorber as a result of the increased steam flow rate. Separate modelling for the absorber indicated that higher capture rates were feasible, but at the expense of additional packed column height. Subsequent desorber size increase as part of an overall process simulation furthermore showed that the reboiler duty could be maintained at levels similar to the value for 90% capture.

These results indicated that if one allowed for a plant design optimisation at a given value for the CO_2 capture rate, a much better energy performance would be likely. The plant design optimisation also included the possibility for two process design modifications to be implemented – intercooling and rich split flow – as they have demonstrated the opportunity for better energy performance without major cost increases (IEAGHG 2014b). In Figure 27 the overall PCC process flow is shown with the two process modifications implemented.

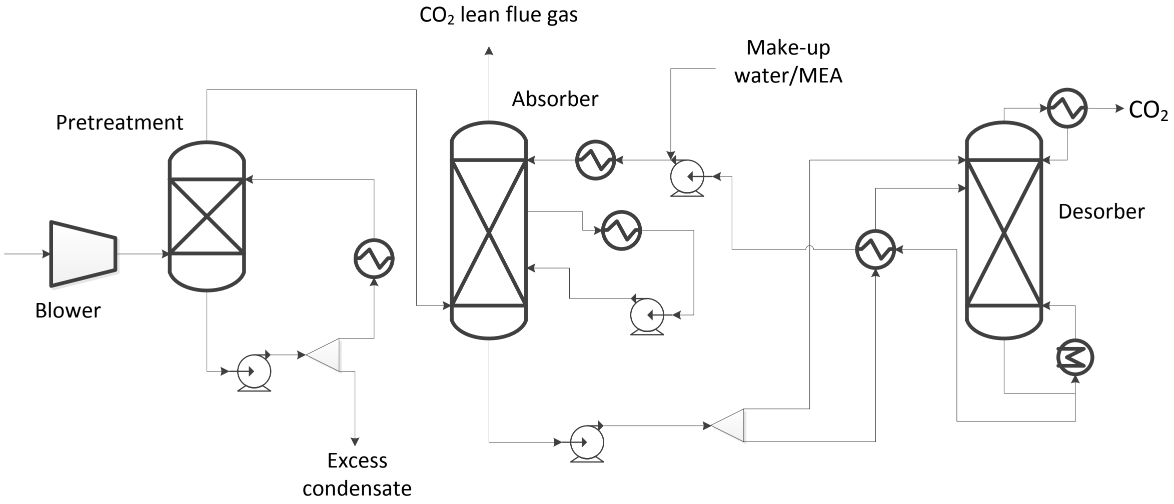

Figure 27 PCC process flow diagram with intercooling and rich split flow

The selected CO_2 capture rates were 90%, 95% and 99% from the flue gases from an ultra-supercritical pulverised coal-fired power plant and a gas-fired combined cycle. Also a case was selected where the amount of CO_2-emitted was equivalent to the amount of CO_2 in the incoming combustion air. This case reflects a CO_2-neutral fossil fuel fired power plant with the capture rate dependent on the inlet CO_2-concentration. A second option to achieve a CO_2-neutral power plant involved the option of 10% biomass co-combustion on the ultra-supercritical pulverised coal-fired power plant with 90% CO2-capture and the performance of such a plant was also assessed.

Flue gas temperatures in both plants are higher than typical liquid absorbent plant operating temperatures and a direct contact cooler was added to bring the temperature back to 40 °C at the absorber inlet. A blower was placed upstream of the cooler, raising the pressure to 108 kPa at this point.

For the PCC process simulations with flue gases in the coal-fired power plant and the gas-fired combined cycle a 30 wt% monoethanolamine (MEA) absorbent with 2 wt% formate was used. Formate was included to represent a typical heat stable salt (HSS) encountered in operational amine plants. The absorber and stripping columns were simulated to operate at 80% of flooding capacity. A packed height of 20 m for the absorber and 10 m (with an additional 2 m rectifying section) in the desorber was used in the simulations. A 20 K temperature approach was chosen for the lean/rich cross heat exchanger. This large temperature approach was used to simulate an in-service, fouled, heat exchanger. The column properties used in the simulations are shown in Table 15.

Table 15 Column properties used in the Protreat® simulations

	Absorber	Stripper
Packed height	20 m	10 m (2m in rectifying section)
Packing type	Mellapak M250X	Mellapak M250X
Column diameter	80% flood	80% flood
Pressure at base of column	105 kPa	185 kPa

An overview of all technical and economical parameters is provided in Appendix A.

8.6 Ultra-supercritical pulverised coal-fired power plant

The performance of an ultra-supercritical coal-fired power plant (900 MW_e gross output) was determined using EBSILON® using the coal specification and other technical data common to IEAGHG studies (Appendix A). The boiler was operated with an air excess of 20% and generated supercritical steam at 600 °C and 29.5 MPa with a single reheat (620 °C; 5.5 Mpa) of the returned steam after expansion in the high pressure steam turbine. After expansion through the medium pressure turbine and low pressure turbine the steam was condensed. The condenser temperature at the average ambient conditions using a natural draught cooling tower was 28.3 °C, equivalent to 4 kPa pressure. A process diagram for the power plant without CO_2 capture is shown in Figure 28.

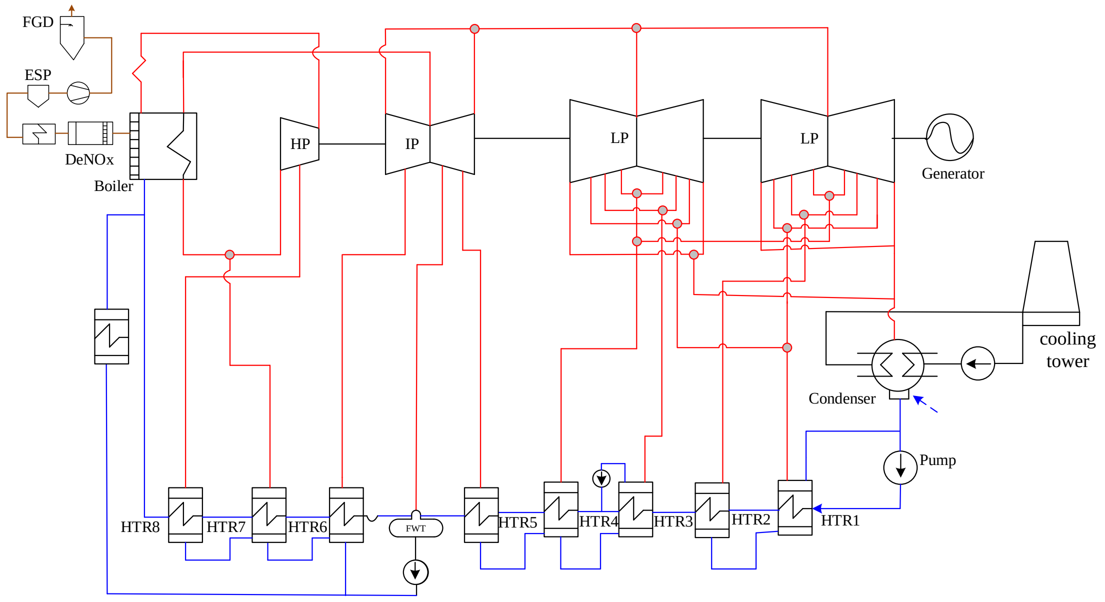

Figure 28 Process flow diagram for ultra-supercritical pulverised coal-fired power station

The flue gas generated by EBSILON® was used as the input to the Protreat® PCC process simulations (Table 16). One PCC process train was simulated in Protreat® and the results formed the basis for the economic modelling.

Table 16 Flue gas details coal-fired power plant

Flow rate, kg/s	826.8
No. trains	3
Temperature, °C	50
Pressure, kPa	101.8
H_2O, mol%	12.1
CO_2, mol%	13.4
N_2, mol%	70.4
Ar and other gases, mol%	0.8
O_2, mol%	3.3

The steam required for the regeneration of the MEA solution was extracted from the cross-over point between the intermediate and low pressure turbines as indicated in Figure 29. The extracted steam was condensed in the reboiler at a temperature of 133 °C. The condensate was used to desuperheat the steam extracted from the steam cycle.

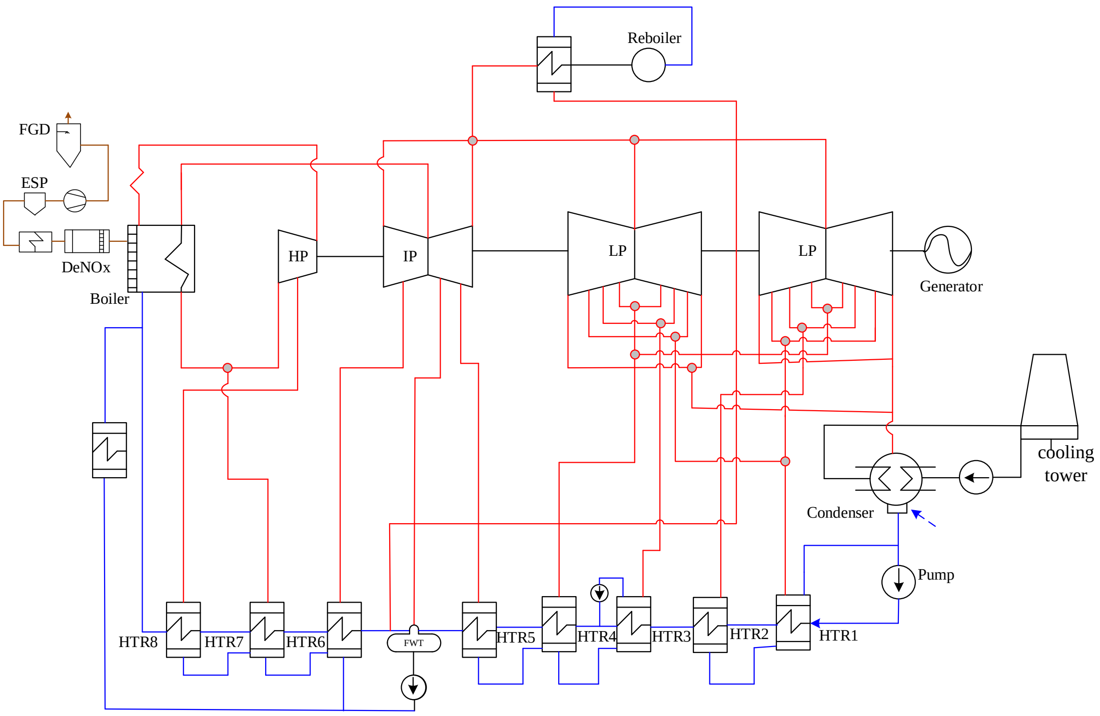

Figure 29 Process flow diagram for an ultra-supercritical pulverised coal-fired power plant with integrated PCC process

The technical performances for the power plants without and with PCC is shown in Table 17. This also includes a power plant with 90% CO_2-capture and 10% biomass co-firing, which has essentially the same technical performance as the power plant with 90% CO_2-capture. The equivalent CO_2-emissions from this plant are taken as zero.

At 90% CO_2-capture there is a significant drop in efficiency of nearly 10 %-points. Increasing the capture rate to 99% leads to an additional 1.8 % efficiency drop. With a PCC process that uses both the intercooling and rich split process modifications the additional drop in efficiency can be limited to 0.9%, demonstrating the significant efficiency benefit of the chosen process modifications.

CO_2 neutrality is achieved at 99.7% CO_2-capture and this results in an efficiency drop of 11.5 %-points, which is significantly higher than for the case in which biomass is co-combusted and 90% CO_2-capture is realised, which results in a 9.9 %-points efficiency decrease. The changes in efficiency are determined by the increased amount of CO_2 captured and the increased specific reboiler duty.

Figure 30 shows that in the standard plant configuration the specific reboiler duty will increase with reduced CO_2-slip (or increased capture rate). Using the intercooling and rich split process modifications the increase can be limited. For example, for the CO_2-neutral power plant (99.7% CO_2-capture) the specific reboiler duty will increase by just over 5%, i.e. from 3.4 at 90% CO_2-capture to 3.6 GJ/tonne CO_2.

The equivalent electrical energy requirement for CO_2-capture in Table 17 shows only a 5% variation for all cases, including the 99.7% CO_2 capture case. Interestingly it is possible to achieve 99% CO_2 capture at a similar equivalent electrical energy requirement as for 90% CO_2-capture, using the combined intercooling/rich split process modification.

Table 17 Technical performance for an ultra-supercritical pulverised coal fired power plant with and without PCC using a 30% MEA solution

Technical performances	USC PC plant w/o PCC	USC PC plant w/ PCC							
		Standard plant			Inter-cooling		Inter-cooling + rich split		10% biomass co-fired SC PC
		90%	95%	99%	99%	99.7%	99%	99.7%	90%
Gross power output (MW)	900	900	900	900	900	900	900	900	900
Auxiliary power (MW)	83	266.1	276.7	299.3	287.8	295.3	282.5	293.5	266.1
Net power output (MW)	817	633.9	623.3	600.7	612.2	604.7	617.5	606.5	633.9
Net plant HHV efficiency (%)	42.5	32.97	32.42	31.24	31.84	31.45	32.11	31.54	32.97
Net plant LHV efficiency (%)	44.4	34.48	33.91	32.68	33.30	32.90	33.59	32.99	34.48
CO_2 generation (t/h)	604	604	604	604	604	604	604	604	543
CO_2 emission (t/h)	604	61	30	6.5	6.3	2.1	6.4	2.1	0.0
CO_2 emission intensity (t/MWh_e)	0.736	0.092	0.045	0.007	0.007	0.000	0.007	0.000	0.000
CO_2 capture (t/h)	0	543	574	597.5	597.7	601.9	597.6	601.9	543
Equivalent electrical energy consumption ($MWh_e/t\ CO_2$)	-	0.337	0.338	0.362	0.343	0.353	0.334	0.350	0.337

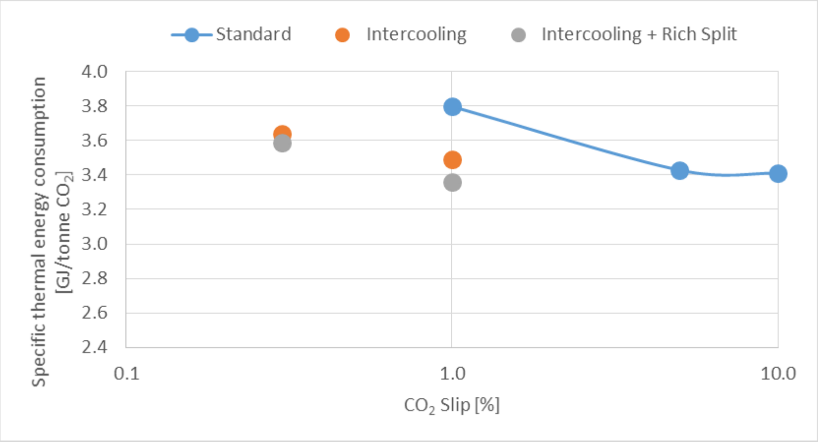

Figure 30 Specific reboiler duty (specific thermal energy consumption) for an ultra-supercritical pulverised coal fired power station as a function of CO_2-slip

Next we carried out the economic performance assessment using 2015 as the most recent year that data for the capture plant cost were available in the Aspen Plus cost estimator.

At 90% CO_2-capture the specific power plant capital costs increased by nearly 60%, as a result of the reduction in output from the power station and the additional PCC plant costs and this increases to 70% at 99.7% CO_2-capture (intercooling and rich split), i.e. a relative cost increase of 6% between the two capture cases.

For the standard PCC plant, the levelised cost of electricity (LCOE) increase with higher CO_2-capture rates as more CO_2 needs to be removed, i.e. the LCOE increases by 69% at 90% CO_2-capture and by 82% at 99% CO_2-capture. At 99% CO_2-capture the LCOE increase can be limited to 77% when the intercooling and rich split process modifications are employed. This case results in marginally, lower CO_2-avoidance costs than the standard plant with 90% CO_2 capture.

The CO_2-avoidance cost show only a marginal increase of less than 5% for all cases considered. Importantly a CO_2-neutral power plant can be realised at an additional cost increase less than 2€/t CO_2 avoided with the combined biomass + 90% CO_2 capture having the lowest avoided cost.

Further techno-economic information including a cost breakdown is given in Appendix B.

Table 18 Economic performance for an ultra-supercritical pulverised coal fired power plant (SCPC) with and without PCC using a 30% MEA solution

Costs (×1000 €) 2015 1st Qtr	USC PC plant w/o PCC	USC PC plant w/ PCC							
		Standard plant			Inter-cooling		Inter-cooling + rich split		10% biomass co-fired SC PC
		90%	95%	99%	99%	99.7%	99%	99.7%	90%
Capital costs									
Total plant costs	1222157	1528404	1535244	1543738	1543876	1556934	1547282	1549493	1559366
Total capital requirement	1342809	1681074	1688684	1698285	1698795	1713393	1703714	1705280	1714376
Specific capital requirement (€/kW_{net})	1647	2654	2712	2830	2777	2835	2759	2813	2704
Fixed O & M									
Annual costs	37674	46331	46506	46725	46728	47064	46816	46873	47127
Variable O & M									
Annual costs	7540	20052	22768	23904	23739	24382	23773	24148	20052
Economic performances									
LCOE (€/MWh)	51.6	87.0	89.7	94.0	92.2	94.0	91.5	93.4	88.7
CO_2 avoided cost (excluding transport and storage) (€/t CO_2)	-	55.0	55.2	58.3	55.7	57.6	54.8	56.9	55.8

8.7 Natural gas-fired combined cycle

The performance of a natural gas fired combined cycle (890 MWe gross output) was determined using EBSILON® using the natural gas specification and other technical data common to IEAGHG studies (Appendix A). The incoming combustion air is compressed to 34 bar, mixed with the natural gas, ignited and expanded through the turbine, generating electricity. After expansion the combustion gas enters the heat recovery steam generator at 620 °C, where steam is produced at 585 °C and 15.9 Mpa. Steam is expanded through the high pressure, intermediate pressure and low pressure turbines, after which it is condensed. The condenser temperature at the average ambient conditions using a forced draught cooling tower was 28.3 °C, equivalent to 4 kPa pressure. A process diagram for the power plant without CO_2 capture is shown in Figure 31.

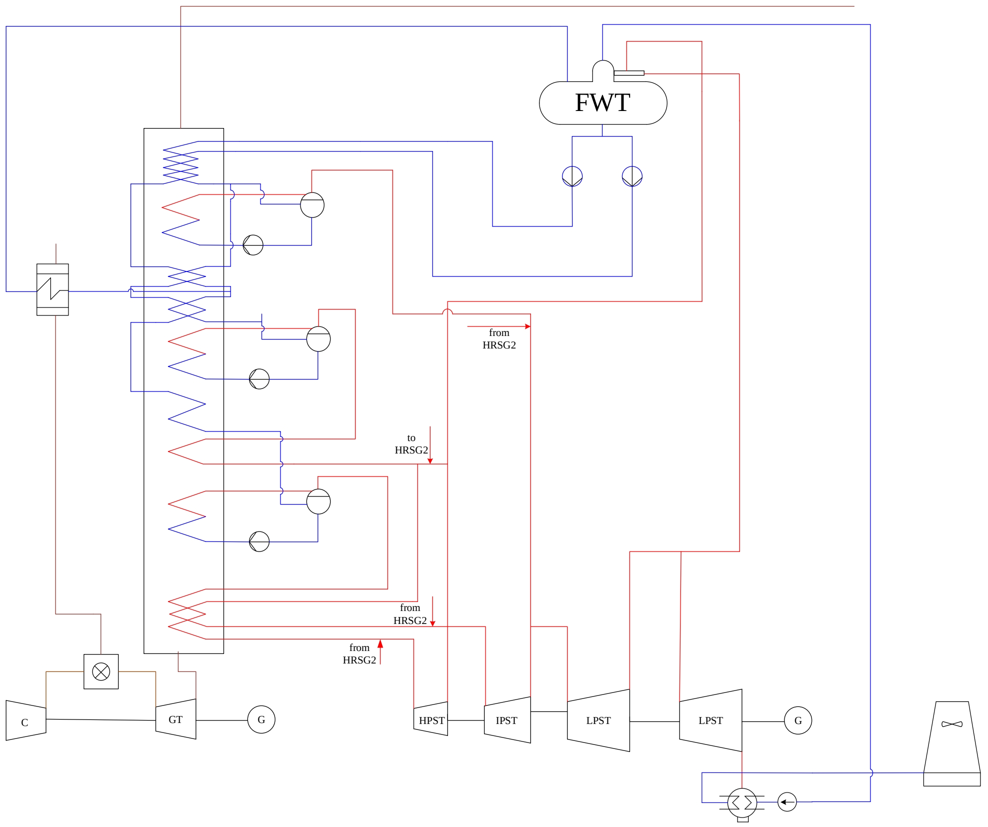

Figure 31 Process diagram for natural gas fired combined cycle

The flue gas generated by EBSILON® was used as the input to the Protreat® PCC process simulations (Table 19). One PCC process train was simulated in Protreat® and the results formed the basis for the economic modelling.

Table 19 Flue gas details for a natural gas fired combine cycle

Flow rate, kg/s	1320
No. trains	4
Temperature, °C	85
Pressure, kPa	101.8
H_2O, mol%	8.5
CO_2, mol%	4.2
N_2, mol%	74.4
Ar and other gases, mol%	0.9
O_2, mol%	12.0

The steam required for the regeneration of the MEA solution was extracted from the cross-over point between the intermediate and low pressure turbines as indicated in Figure 32. The extracted steam was condensed in the reboiler at a temperature of 133 °C. The condensate was used to desuperheat the steam extracted from the steam cycle.

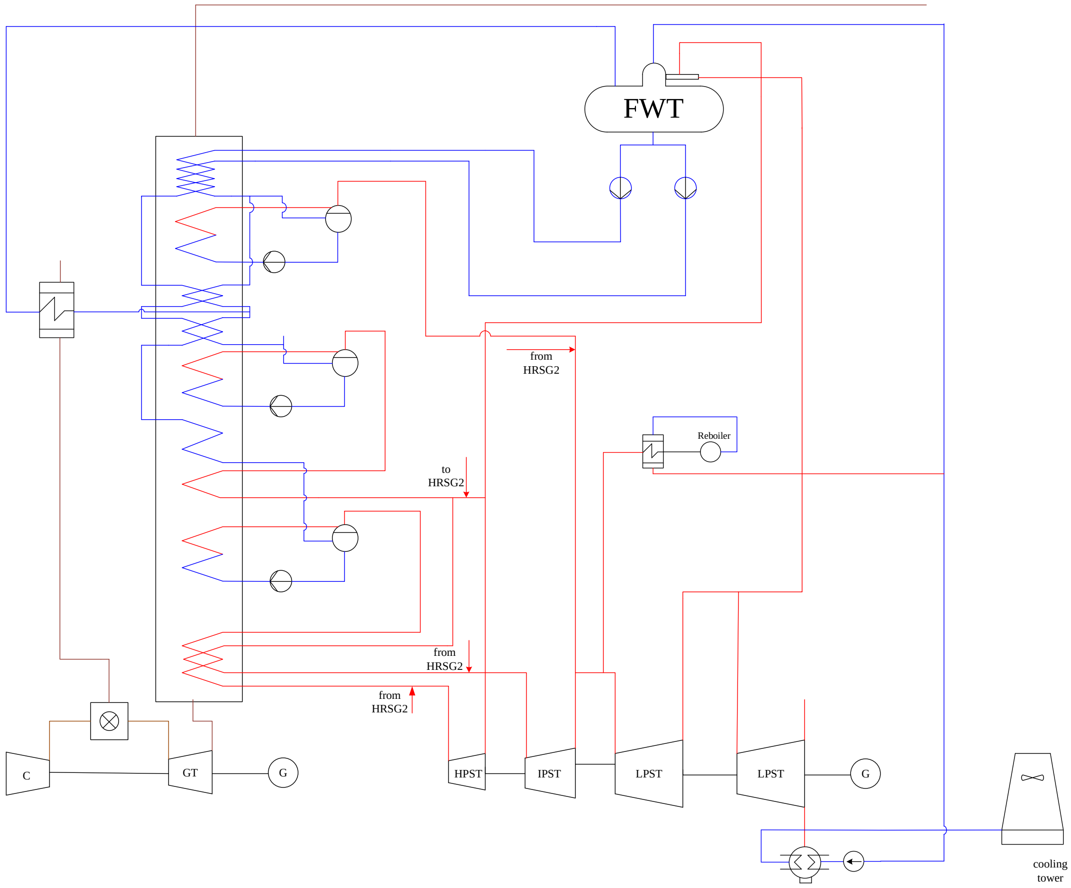

Figure 32 Process flow diagram for a natural gas fired combined cycle with integrated PCC

The technical performance for the power plants without and with PCC is shown in Table 20.

At 90% CO_2-capture there is a significant drop in efficiency of nearly 10 %-points. Increasing the capture rate to 99% leads to an additional 2.2 % efficiency drop. With a PCC process that uses intercooling the efficiency was not improved. The addition of the rich split process modification also did not indicate an efficiency improvement and was not further modelled in detail. CO_2 neutrality is achieved at 99.1% CO2-capture and results in an efficiency drop of 12.2%. The changes in efficiency are determined by the increased amount of CO_2 captured and the increased specific reboiler duty.

Figure 33 shows that the effect of CO_2 slip on the specific reboiler duty (specific thermal energy consumption) is limited. For 5 and 10% CO_2 slip (95 and 90% CO_2-capture, respectively) the reboiler is around 3.6 GJ/tonne CO_2. At 1% CO_2 slip the specific reboiler duty is around 4.4 GJ/tonne CO_2 for the standard PCC plant and the effect of intercooling is negligible. Achieving high CO_2-capture rates, tending toward CO_2-neutrality comes at a relatively high thermal energy consumption. This is also reflected in a higher value for the equivalent electricity consumption, shown in Table 20. The use of intercooling leads to a worsening of the PCC energy performance at a CO_2-capture rate of 99%.

Table 20 Technical performance for a natural gas fired combined cycle with and without PCC using a 30% MEA solution

Technical performances	**NGCC plant w/o PCC**	**NGCC plant w/ PCC**				
		Standard plant			**Inter-cooling**	
		90%	**95%**	**99%**	**99%**	**99.1%**
Gross power output (MW)	890	890	890	890	890	890
Auxiliary power (MW)	12	162	170	199	199	201
Net power output (MW)	878	728	720	691	691	689
Net plant HHV efficiency (%)	52.66	43.91	43.37	41.94	41.7	41.63
Net plant LHV efficiency (%)	58.25	48.57	47.97	46.39	46.13	46.05
CO_2 generation (t/h)	310	310	310	310	310	310
CO_2 emission (t/h)	310	30.2	15.8	2.9	2.9	2.9
CO_2 emission intensity (t/MWh_e)	0.349	0.0373	0.0176	0.000	0.000	0.000
CO_2 capture (t/h)	0	279.4	293.8	306.7	306.7	306.7
Equivalent electrical energy consumption ($MWh_e/t\ CO_2$)	-	0.523	0.526	0.583	0.596	0.599

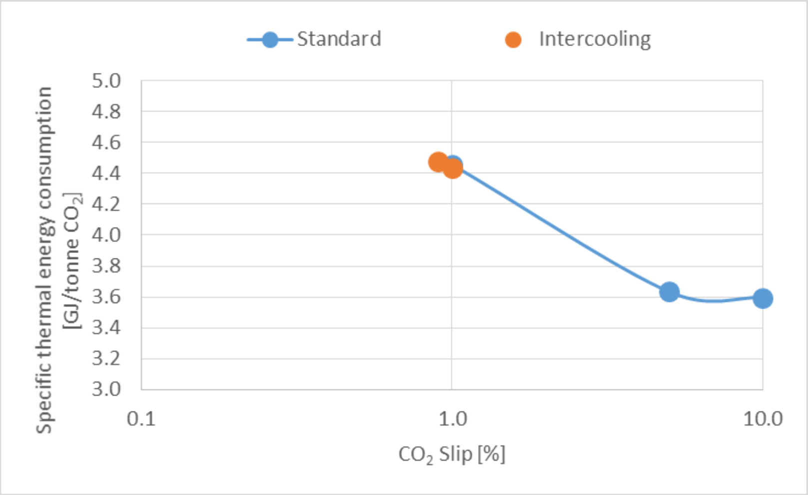

Figure 33 Specific reboiler duty (specific thermal energy consumption) for the natural gas fired combined cycle (NGCC) as a function of CO_2-slip

Next we carried out the economic performance assessment using 2015 as the most recent year that data for the capture plant cost were available in the Aspen Plus cost estimator, with the results summarised in Table 21.

At 90% CO_2-capture the specific power plant capital costs increase by 72%, as a result of the reduction in output from the power station and the additional PCC plant costs and this increases to 82% at 99% CO_2-capture (standard plant), i.e. a relative cost increase of 7% between the two capture cases.

For the standard PCC plant, the LCOE increases with higher CO_2-capture rates as more CO_2 needs to be removed, i.e. the LCOE increases by 47% at 90% CO_2-capture and by 56% at 99% CO_2-capture. At 99% CO_2-capture there is no economic benefit from the intercooling process modifications, as the LCOE is slightly higher.

The CO_2-avoidance costs are lowest for 95% CO_2 capture; at 99% CO2-capture the CO_2-avoidance cost are ~9€/t CO_2 higher. A CO_2-neutral natural gas fired combined cycle can be realised at and additional cost increase of 8€/t CO_2 avoided compared to the 90% CO_2-capture case. This represents a 10% increase.

Further techno-economic information including a cost breakdown is given in Appendix B.

Table 21 Economic performance for a natural gas fired combine cycle with and without PCC using a 30% MEA solution

Costs (×1000 €) 2015 1st Qtr	NGCC plant w/o PCC	NGCC plant w/ PCC				
		Standard plant			Inter-cooling	
		90%	95%	99%	99%	99.1%
Capital costs						
Total plant costs	765087	1117392	1121595	1128730	1141439	1141656
Total capital requirement	835693	1172792	1177442	1185323	1199285	1199525
Specific capital requirement (€/kW)	939	1611	1629	1716	1737	1740
Fixed O & M						
Annual costs	29157	39667	39805	40041	40461	40469
Variable O & M						
Annual costs	3412	11916	12310	12815	12838	12850
Economic performances						
LCOE (€/MWh)	52.9	77.6	78.9	82.7	83.1	83.3
CO_2 avoided cost (excluding transport and storage) (€/t CO_2)	-	79.3	78.6	85.5	86.6	87.1

9 Zero emissions from fossil-fuel-fired power plants – final considerations

Environmental considerations

The electricity industry has an increasing number of technologies at its disposition based on renewable energy or nuclear energy that are essentially near-zero emission. It is therefore very likely that pressure will mount for the fossil-fuel-based technologies to have a similarly low carbon footprint.

At a power plant facility, this can be achieved by further increasing CO_2 capture levels and/or the co-utilisation of biomass in the power station while maintaining capture levels. A biomass co-combustion coal-fired power plant is likely to be easier to implement than a biomass-only power plant, provided the biomass is of the right quality. Implementing CO_2 capture on such plants would also be an excellent stepping stone towards the use of bioenergy with CO_2 capture and storage to achieve below zero (or negative) emissions.

The study results indicate that at increased CO_2-capture rates to 99% the indirect emissions, in particular the fugitive emissions, from coal and gas fired power plants would be dominant. The indirect emissions as estimated in this study from median fugitive emission factors would also be higher than the reported median indirect emissions from most types of renewable energy or nuclear energy plants. This highlights the need to reduce the fugitive emissions in addition to lowering CO_2-emissions at the power plant.

It is suggested that the societal acceptance of CO_2 capture and storage might be improved if it can be represented as a zero emission technology at the power plant level, making CCS plants quite comparable to renewable and/or nuclear energy plants. The study results indicate that this is achievable by increasing capture rates in a post-combustion capture process or the co-combustion of biomass with integrated capture of CO_2.

Technological considerations

This study has shown in detail that CO_2 capture rates for amine-based post-combustion capture can be increased considerably without major additional cost compared with 90% CO_2 capture. It would require a dedicated process design aimed at the higher CO_2-capture rate. A CO_2-neutral power plant is achievable at 99.7% CO_2-capture for an ultra-supercritical coal-fired power station and 99.1% CO_2-capture for a gas-fired combined cycle. At these capture rates the amount of CO_2 emitted is equal to the amount of CO_2 present in the incoming combustion air. This will require further demonstration in pilot plants and larger-scale demonstration plants using a range of commercial amine solutions.

Demonstration of similar zero emissions approaches for the other process routes (oxyfuel and pre-combustion) is also required. This should not present a major challenge for oxyfuel processes as CO_2 can be recovered from vent gases and/or the O_2-purity can be increased, albeit at an additional energy requirement. In pre-combustion the fuel conversion and CO_2-separation process would need to be optimised for the maximisation of the CO_2 capture rate; in case of oxygen being used in the fuel conversion process its purity would also need optimisation.

The wider suite of capture technologies appears to be amenable to increasing CO_2 capture rates, and there is a need to demonstrate this in pilot plants. Some capture technologies, e.g. polymeric membranes or physical sorbents for PCC, do not lend themselves well to higher capture rates and might have an economic optimum at capture rates lower than 90%. In such cases a hybrid process design involving biomass co-combustion with lower levels of CO_2-capture might be advantageous when aiming for a zero-emission power plant.

Economic considerations

The introduction of CO_2 capture at a power plant will result in an increase in the cost of generating electricity and the higher the amount of CO_2 captured, the higher the cost increase. In the case of post-combustion CO_2 capture, the literature information indicates that the cost per tonne of CO_2 emission avoided has an optimum value that is determined by the CO_2 capture rate, and will be in the range 70-95%. The decision to increase CO_2 capture rates will therefore be an economic one unless regulations aiming for zero emissions are put in place.

The techno-economical assessment has indicated that the PCC technology can be optimised to achieve CO_2-neutrality with, at most, a 4% increase in the cost per tonne avoided for a ultra-supercritical pulverised coal fired power station (equivalent to ~ 2€/t CO_2) and a 10% increase in the cost per tonne CO_2 avoided for a natural gas fired combined cycle (equivalent to ~ 8€/t CO_2). Compared to a power plant without CO_2 capture, the increase in electricity generation costs for a CO_2-neutral ultra-supercritical coal fired power plant compared would be 81%; for a gas-fired combined cycle it would be 57%. These results are based on capture process performances determined for a 30% mono-ethanolamine solution.

Policy considerations

The study has demonstrated that higher capture levels in CCS plants are feasible for the wide range of capture routes and capture technologies. Using PCC as the detailed example, it has also been demonstrated that a zero-emission fossil fuel fired power station is achievable at marginally increased costs compared to the usual 90% CO_2-capture rate. In future technology assessments and emission reduction scenarios this needs to be taken into account as current practices seem to impose an artificial limit on the level of emission reduction.

Achieving zero emissions from fossil fired power stations, amplifies the need to reduce indirect emissions from the fossil fuel chain. Indirect emissions are dominated by the fugitive emissions from the coal and gas fuel chains. When CO_2-capture rates are increased beyond the usual 90%, the indirect emissions will dominate the overall emissions originating from the use of fossil fuels after implementation of CCS. Fugitive emissions can vary widely and are dependent on the fuel type and its origin, handling and transport. For the fuels specified for IEAGHG studies the indirect emissions in the case of 99% CO_2-capture were estimated to account for 81% of the total emissions for an ultra-supercritical coal fired power station and 96% of the total emissions for a gas-fired combined cycle.

Appendix A Data used in study

The fuel data used in this study were taken from “Criteria for Technical and Economic Assessment of Plants with Low CO_2 Emissions”, Version C-4, February 2013, provided by the IEA GHG.

Table A.1 Fuel data used in this study

Coal analysis	
Coal type	Eastern Australia, open cast bituminous
Moisture (as-received), wt%	9.5
Ash (as-received), wt%	12.2
Carbon (dry ash free), wt%	82.5
Hydrogen (dry ash free), wt%	5.6
Oxygen (dry ash free), wt%	8.97
Nitrogen (dry ash free), wt%	1.8
Sulphur (dry ash free), wt%	1.1
Chlorine (dry ash free), wt%	0.03
Higher heating value (as-received), MJ/kg	27.06
Lower heating value (as-received), MJ/kg	25.87
Hardgrove index	45
Ash analysis, wt%	
SiO_2	50.0
Al_2O_3	30.0
Fe_2O_3	9.7
CaO	3.9
TiO_2	2.0
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7
Ash fusion temp (reducing), C	1350

Natural gas analysis	
Methane, vol%	89.0
Ethane, vol%	7.0
Propane, vol%	1.0
Butane, vol%	0.1
Pentane, vol%	0.01
CO_2, vol%	2.0
Nitrogen, vol%	0.89
Pressure, Mpa	7
HHV, MJ/kg	51.473
LHV, MJ/kg	46.502

Table A.2 Emission limits

Emission limits (solid fuel combustion)	
SO_2, mg/Nm^3 (6% O_2 combustion)	150 / 50
NO_X, (as NO_2) mg/Nm^3 (6% O_2 combustion)	150 / 10
Particulates, mg/Nm^3 (6% O_2 combustion)	10 / -

Table A.3 Cooling system parameters

Ambient conditions	
Air temperature (dry-bulb, average), C	9
Humidity (average), %	80
Pressure (average), kPa	101.3
Cooling system	
Mechanical /natural draught cooling towers	
Cooling water inlet-outlet, C	11
Cooling water approach to wet bulb temperature, C	7
Turbine condenser minimum ΔT, C	3

Table A.4 Economic parameters

Total Plant Cost (TPC)	
Installed costs	Equipment costs + material costs + labour costs
Engineering contractor's fees	10% of installed costs
Project contingency	10% of (installed costs + engineering contractor's fee)
Process contingency (only for CCS)	16% of (installed costs + engineering contractor's fee)
Total Capital Requirement (TCR)	
Owners costs and fees	7% of TPC
Spare parts	0.5% of TPC
Start-up costs:	
(1) Maintenance and operating and support labour costs	3 month
(2) Maintenance materials	1 month
(3) Chemicals, consumables and waste disposal costs	1 month
(4) Fuel cost	25% of 1 month
(5) Modifications	2% of TPC
Construction time	
Pulverised coal and natural gas plants	3 years
Capital expenditure schedule	
Pulverised coal and natural gas plants	20%/45%/35% of TPC, year 1-3
Capacity factor	
All except year 1	85% (7446 hr)
Year 1	50% (4380 hr)
Discount rate	
Plant construction and operation	8%
Operating life	

Base case	25 years
Fuel prices	
Coal	2.5 €/GJ
Natural gas	5.0 €/GJ
Biomass	3.3 €/GJ
Fixed operating costs	
Maintenance costs	
PC plant	1.5% of TPC/year
NGCC	2.2% of TPC/year
Maintenance materials	60% maintenance costs
Maintenance labour	40% maintenance costs
Operating labour cost,	60 k€/person-year
Number of operators	
PC plant	16
PC + CO_2 capture	18
NGCC plant	6
NGCC + CO_2 capture	7
Number of operating shifts	5
Administrative/support labour	30% of operating labour + 12% of maintenance cost
Insurance cost,	0.5% of TPC
Local taxes and fees	0.5% of TPC
Variable operating costs	
Raw process water	0.2 €/m^3
Limestone	20 €/t
MEA	1.7 €/kg
Corrosion inhibitor	20% of MEA cost

Soda ash	0.56 €/kg
Special waste disposal costs	20.5 €/kg
CO_2 transport and storage,	10 €/t CO_2 stored (not used in this study)

Appendix B Techno-economic results for power plants with/without post-combustion CO_2-capture

Table B.1 Ultra-supercritical pulverised coal fired power plant (900 MW Gross)

Costs (/1000 €) 2015 1st Qtr	**USC PC**	**PCC (three process trains)**						
		Standard plant			**Inter-cooling**		**Inter-cooling + rich split**	
		90%	**95%**	**99%**	**99%**	**99.7%**	**99%**	**99.7%**
Capital costs								
Equipment	-	119548	122328	126777	128126	131108	129242	131030
Materials	-	76617	78597	80040	78911	84511	79589	79320
Labour	-	24792	24967	25203	25083	25922	25747	25823
Engineering contractors fees	-	22096	22589	23202	23212	24154	23458	23617
Process contingency	-	24305	24848	25522	25533	26570	25804	25979
Project contingency	-	38888	39757	40836	40853	42511	41286	41566
Total plant costs	1222157	306246	313087	321581	321719	334777	325124	327336
Owners costs and fees	85551	21437	21916	22511	22520	23434	22759	22914
Spare parts	6111	1531	1565	1608	1609	1674	1626	1637
Start-up	28990	9051	9307	9776	10138	10699	11396	10584
Total capital requirement	1342809	340265	345875	355476	355986	370584	360905	362471
Fuel cost								
Coal	128817	128817	128817	128817	128817	128817	128817	128817

Costs (/1000 €) **2015 1st Qtr**	**USC PC**	**PCC (three process trains)**						
		Standard plant			**Inter-cooling**		**Inter-cooling + rich split**	
		90%	**95%**	**99%**	**99%**	**99.7%**	**99%**	**99.7%**
Annual fixed O & M								
Operating labour	4800	5400	5400	5400	5400	5400	5400	5400
Maintenance	18332	22926	23029	23156	23158	23354	23209	23242
Administrative and support	2320	2720	2725	2731	2732	2741	2734	2736
Taxes and insurance	12222	15284	15352	15438	15438	15570	15472	15494
Subtotal	37674	46331	46506	46725	46728	47064	46816	46873
Annual variable O & M								
Cooling and makeup water	1021	3772	3898	4000	3876	4408	3931	4180
Catalyst	3022	3022	3022	3022	3022	3022	3022	3022
Limestone	1108	1108	1108	1108	1108	1108	1108	1108
MEA	-	6888	7525	7560	7562	7616	7561	7616
Corrosion inhibitor	-	1378	1451	1512	1512	1523	1512	1523
Other chemicals	2389	3884	4989	5927	5884	5930	5864	5924
Waste disposal	-	775	775	775	775	775	775	775
Subtotal	7540	20052	22768	23904	23739	24382	23773	24148
Economic performances								
LCOE (€/MWh)	51.6	87.0	89.7	94.0	92.2	94.0	91.5	93.4
CO_2 avoided cost (€/t CO_2)	-	55.0	55.2	58.3	55.7	57.6	54.8	56.9
CO_2 captured cost (€/t CO_2)	-	31.3	31.4	32.7	31.6	32.6	31.3	32.2

Table B.2 Natural gas-fired combined cycle (890 MW Gross)

Costs (/1000 €) **2015 1st Qtr**	**NGCC**	**PCC (four process trains)**				
		Standard plant			**Inter-cooling**	
		90%	**95%**	**99%**	**99%**	**99.1%**
Capital costs						
Equipment	-	96926	98401	101391	102937	103049
Materials	-	101688	102732	104588	109796	109834
Labour	-	22252	22766	23067	25482	25489
Engineering contractors fees	-	22087	22390	22905	23822	23837
Process contingency	-	24295	24629	25195	26204	26221
Project contingency	-	38872	39406	40312	41926	41954
Total plant costs	765087	306120	310323	317458	330167	330384
Owners costs and fees	53556	21428	21723	22222	23112	23127
Spare parts	3825	1531	1552	1587	1651	1652
Start-up	13225	8020	8150	8363	8662	8669
Total capital requirement	835693	337099	341749	349720	363592	363832
Annual fuel cost						
Natural gas	226519	226519	226519	226519	226519	226519

Costs (/1000 €) **2015 1st Qtr**	**NGCC**	**PCC (four process trains)**				
		Standard plant			**Inter-cooling**	
		90%	**95%**	**99%**	**99%**	**99.1%**
Annual fixed O&M						
Operating labour	1800	2100	2100	2100	2100	2100
Maintenance	17848	24583	24675	24832	25112	25116
Administrative and support	1397	1810	1814	1822	1835	1836
Taxes and insurance	8112	11174	11216	11288	11414	11416
Subtotal	29157	39667	39805	40041	40461	40469
Annual variable O&M						
Cooling and makeup water	1122	2661	2680	2667	2794	2790
MEA	-	3531	3727	3884	3884	3888
Corrosion inhibitor	-	706	745	777	777	778
Other chemicals	2290	4338	4478	4807	4703	4714
Waste disposal	-	680	680	680	680	680
Subtotal	3412	11916	12310	12815	12838	12850
Economic performances						
LCOE (€/MWh)	52.9	77.6	78.9	82.7	83.1	83.3
CO_2 avoided cost (€/t CO_2)	-	79.3	78.6	85.5	86.6	87.1
CO_2 captured cost (€/t CO_2)	-	54.4	53.7	57.1	58.0	58.2

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Evaluating technology options to mitigate greenhouse gas emissions

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