Zero emissions platform

CCS for industry

Modelling the lowest-cost route to decarbonising Europe

European Technology Platform for Zero Emission Fossil Fuel Power Plants

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Key conclusions

- Energy-intensive industries account for a quarter of EU CO_2 emissions and cannot reduce them substantially *without* CO_2 Capture and Storage (CCS).

- The absence of CCS support measures in the model (upfront public investment in CO_2 transport and storage + incentives for energy-intensive industries) not only delays CCS deployment to 2040, but leads to a CO_2 reduction of only 68% by 2050 – well below EU targets of 80-95% for power and industry.

- Investment in CO_2 transport and storage infrastructure must start *now* in order to deploy CCS widely from 2025 – a delay of even 10 years will cost power and industry an extra €200 billion to reach these EU targets. It will also result in a forced doubling of the annual CCS deployment rate to 15-20 GW for power alone which is unrealistic given supply constraints for the delivery of power plants, CCS infrastructure *and* the necessary skills. Hence delaying CCS deployment until 2035, while possible to model, risks severely limiting its optionality.

- When CCS is *not* part of the portfolio, the cost of reaching the EU's CO_2 reduction target for power increases by at least €1-1.2 trillion. The EU's target for industry, on the other hand, is not achievable – in any scenario.

- **2015 to 2025 is therefore a critical time for CCS deployment, for which support measu*res* are urgently required:**

    1. <u>Incentives for energy-intensive industries</u>
        - **The Innovation Fund** presents a once-in-a-decade opportunity to support both power and energy-intensive industries in developing and implementing full-chain CCS projects. It should build on the experience and learning of the NER300, accommodate a wide range of industrial sectors and support projects across different scales.
        - Member State policies, such as **feed-in premia or contracts for difference** (CfD), will play a key role in providing early investors with security of income.

    2. <u>Upfront public investment in transport and storage infrastructure</u>
        - As clusters of power and industrial emitters will significantly reduce the costs of CCS, **€6-12 billion investment is needed in 3-6 clusters**, each with 20 Mt_{CO_2}/year capacity, in order to kick-start deployment. This means creating fit-for-purpose funding for CCS infrastructure development – for example, through the proposed Innovation and Energy Modernisation Funds, regional and structural funds, Horizon 2020 and the Connecting Europe Facility (CEF).

    For more information, please see ZEP's Executable Plan for Enabling CCS in Europe.[1]

- The modelling assumes that the long-term driver for CO_2 reduction is an increasing CO_2 price under the EU ETS (or similar). However, investments in CCS replace a variable CO_2 price with long-term financial liability which requires dependable boundary conditions. If the costs to reduce CO_2 *surpass* the capacity of industry sectors to pay, a premium or CfD may still be required to drive the change.

- When CCS is deployed, the value of electricity storage in reducing decarbonisation costs is limited. However, in the longer-term, electricity storage mechanisms will potentially play an important role in reducing the total cost of CO_2 reduction for power grids with high renewable penetration when CCS is not available.

[1] www.zeroemissionsplatform.eu/library/publication/255-executableplan.html

- Large geological formations identified in Europe have more than sufficient CO_2 storage capability – ~80 Gt_{CO2} – mainly deep saline aquifers. This is consistent with the model's assumption of a 500 km offshore pipeline with offshore storage in a deep saline aquifer.

- It is clear that Europe's power sector will continue to feature a variety of technologies and fuels in which CCS will be both competitive and needed. Indeed, decarbonised coal and gas are essential to integrate solar and wind cost-effectively into the grid – for affordable, reliable, near-zero-CO_2 power.

- Following the original publication of this report and at the request of the Advisory Council some additional sensitivity studies were conducted to assess the impact of lower fixed Operation and Maintenance costs for the Solar PV technology. The O&M cost of Solar PV in 2050 was reduced from 26 €/kW/a to 19.5 €/kW/a and 13 €/kW/a as two sensitivities (see also Figures 27 and 28). The effect is to shift the optimisation to build more PV and less of other technologies. The change does not affect the principle conclusion of the report that adding CCS to the mix leads to the lowest cost option to achieve the emissions targets by 2050. Not having CCS available will increase the cumulative costs by 1-1.2 trillion Euro, depending on the assumed O&M costs for Solar PV. These sensitivities demonstrate that the importance of a mix of technologies including CCS on Industrial and Power emitters is robust to variations in the assumptions. We remind the reader that the cost assumption for the capex of PV in the low PV cost case used in this report includes a 5 fold reduction in the cost of PV from today's cost out to 2050, a very aggressive assumption.

Contents

1 CCS: an indispensable component for decarbonising Europe

ZEP has already modelled the lowest-cost route to decarbonising European power

Together with renewables, CO_2 Capture and Storage (CCS) will play a critical role in achieving Europe's energy, climate and societal goals: it is an indispensable component of national and global decarbonisation pathways drawn up by the IPCC, the IEA and the European Commission. Indeed, the EU 2050 Energy Roadmap relies heavily on CCS to meet EU-wide decarbonisation targets.

Electricity production alone accounts for a third of Europe's GHG emissions, with a single power plant emitting ~1-5 million tonnes of CO_2 every year. In order to identify how low-carbon technologies can reduce power emissions most cost-effectively in the horizon to 2050, the Zero Emissions Platform (ZEP) therefore developed a model[2] based on an existing model from the Norwegian University of Science and Technology (NTNU) and linked it to the Global Change Assessment Model (GCAM).

It is designed to select the lowest-cost investments to meet expected electricity demand, while replacing plants that exceed a defined lifetime – country by country. It is also unique in that it not only takes into account optimised operating costs hour-by-hour, but also has a dispatch model for renewable power based on capacity factors and historic weather data.

This resulted in the publication of two landmark reports:

1. 2013: "*CO_2 Capture and Storage (CCS): recommendations for transitional measures to drive deployment in Europe*"[2] confirmed the critical role of CCS in meeting EU decarbonisation targets and the need for transitional measures, including grants for early movers and feed-in premia to provide security of income. This led directly to the inclusion of CCS in the 2030 EU Energy and Climate Policy Framework.

2. 2014: "*CCS and the electricity market: modelling the lowest-cost route to decarbonising European power*"[3] modelled much higher shares of renewable energy sources (RES) – mainly photovoltaics and onshore wind – at the request of the European Commission. Using a generic electricity storage model, this showed that a combination of CCS and RES leads to 20-50% lower electricity generation costs in 2050, compared to a RES-only path.

Extending the model to include energy-intensive industries

However, with direct industry-related emissions accounting for a quarter of total EU CO_2 emissions, it is clear that Europe must look beyond the power sector to include core industries such as refining, steel and cement.

Not only is CCS the *only* option for substantially reducing CO_2 emissions in these industries, but the costs of CO_2 transport and storage – 10-30% of the total CCS costs – can be significantly reduced by clustering power and industrial emitters.

ZEP has therefore now extended the modelling even further to include **industrial CCS applications,** the effect of **clustering**, as well as **additional electricity storage technologies**. (The previous report[3] introduced a generic electricity storage technology to the model; this has now been expanded to include typical battery storage and power to hydrogen). In this, ZEP has been assisted by closer collaboration not only with energy-intensive industries, but power equipment suppliers and the European electricity storage association.

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[2] See www.zeroemissionsplatform.eu/library/publication/240-me2.html for full details of model equations and cost parameters; also Chapter 4

[3] www.zeroemissionsplatform.eu/library/publication/253-zepccsinelectricity.html

2 Modelling the deployment of CCS in industry

Energy-intensive industries account for a quarter of EU CO_2 emissions

In 2010, direct industry-related emissions accounted for over 900 million tonnes (Mt) of CO_2 – a quarter of total EU27 CO_2 emissions of which iron and steel, cement and petroleum refining accounted for ~50% (Figure 1).

CCS is the only technology which can substantially reduce these emissions, allowing Europe to maintain a competitive economy, retain and expand employment – *and* achieve its climate goals. Indeed, in its "2˚C Scenario", the IEA forecasts that industrial applications will have a significant impact on CO_2 reduction through to 2050.[4]

Steel, cement and refineries were therefore included in ZEP's model. (The chemicals industry was not considered due to its high diversity which makes accurate modelling difficult.)

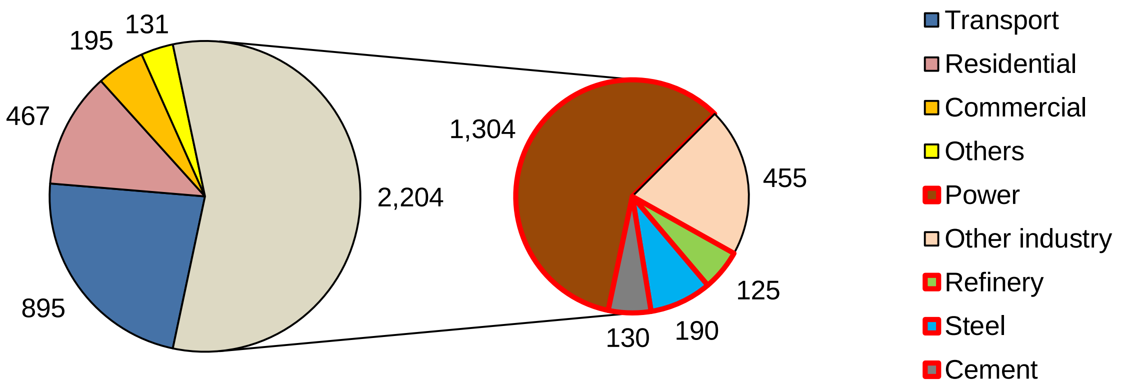

Figure 1: EU27 2010 total CO_2 emissions and direct CO_2 industrial emissions in Mt (Using data from UNFCCC National Inventory Submissions, 2012)

The use of advanced energy-efficient industrial processes and equipment (e.g. heat recovery, use of scrap materials etc.) are key to reducing resource consumption and GHG emissions from industry. However, many industrial processes in the EU are already operating close to the theoretical limits of efficiency, while the release of CO_2 is an integral part of several manufacturing processes which cannot be avoided.

The adoption of current best available and best practice technologies (BAT, BPT) is therefore not sufficient to reach targets set to avoid dangerous climate change. To achieve the drastic reductions in CO_2 emissions needed, the European Commission therefore acknowledges that CCS must be widely deployed in industry from 2035.[5] This requires project development, pipeline corridor development and storage appraisal to occur 10-15 years prior and the first tranches of transport and storage infrastructure to be designed, consented and built within that 10-15 year lead time.

The products of Europe's energy-intensive industries are openly traded on the global market. International competitiveness is therefore key to ensuring their economic prosperity, securing European employment and skills, and encouraging innovation throughout industry.

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[4] www.iea.org/publications/freepublications/publication/ccs_industry.pdf

[5] European Commission, 2011: Roadmap for moving to a competitive low-carbon economy in 2050

The financial and economic crisis since 2008 and the ensuing austerity measures in many Member States have had consequential effects on EU industrial production. While overall EU CO_2 emissions may have reduced as a result of the drop in production, there is little to gain in terms of global CO_2 reductions by it being displaced elsewhere – especially to regions with less stringent environmental requirements. It is also likely to undermine EU popular support for climate measures due to the negative employment effects, in turn making it politically unfeasible to introduce such measures.

Calculating the costs of CO_2 avoidance

Modelling industrial emitters first requires an estimation of the costs of industrial CCS. A generally accepted measure is the cost of CO_2 avoided, i.e. the difference in costs between a plant with CCS and a reference plant *without* CCS, divided by the difference in emission intensity between them:

$$\boldsymbol{Cost\ of\ CO2\ avoided} = \frac{\boldsymbol{Cost\ per\ unit\ product\ (CCS) - Cost\ per\ unit\ product\ (Ref)}}{\boldsymbol{t_{CO2}\ per\ unit\ product\ (Ref) - t_{CO2}\ per\ unit\ product\ (CCS)}}$$

CO_2 avoidance costs often only consider CO_2 capture and compression costs. However, in order to understand the true cost of CO_2 avoided, transport and storage (T&S) costs must also be added.

It is important to stress the difference between *captured* and *avoided* CO_2. Since the capture process itself consumes energy, it is also a source of additional CO_2 that needs to be captured. Figure 2 below illustrates the difference between captured and avoided CO_2 for various types of power plants as the same principle also applies to industrial emitters.

CO_2 avoidance costs for fossil power plants have already been the subject of an extensive study by ZEP,[6] which concluded that a value of 40-60 €/t_{CO2} avoided can be expected for coal and lignite plants, and up to 100€/t_{CO2} for natural gas-fired plants. This includes transport and storage costs, which assume a 500 km offshore pipeline with offshore storage in a deep saline aquifer. The main difference between coal- and gas-fired plants is the CO_2 concentration in the flue gas which is 10-14 vol% for coal and 3-6 vol% for gas.

In order to compare this with the costs of industrial CCS, it is necessary to re-capitulate some of the assumptions that led to these figures. As an example, ZEP considered two variants of hard coal plants as reference cases: a BASE plant makes conservative assumptions on costs using today's technology choices, while an OPTI plant uses low-end costs based on more optimised power plant designs. This report only covers post-combustion technology that is assumed will also be useable for industrial applications. Further assumptions are a plant load factor of 85.6% equal to 7,500 operating hours per year, a WACC of 8% and a lifetime of 40 years.

CO_2 avoidance costs (without T&S) are calculated as the difference in LCOE divided by the difference in emission intensity (37.2 €/t_{CO2} = (72.9-48.2) €/MWh/(0.759-0.091) t_{CO2}/MWh for BASE). Table 1 below shows a difference in total costs of 500 and 300 M€ between the post-combustion and reference case for the BASE and OPTI plants, respectively. This mainly represents the costs for the capture and compression equipment to capture 3.8 Mt $_{CO2}$ per year. The avoidance rate is the effective reduction of CO_2 emissions per unit of product – for fossil power plants it is ~88%.

[6] www.zeroemissionsplatform.eu/library/publication/165-zep-cost-report-summary.html

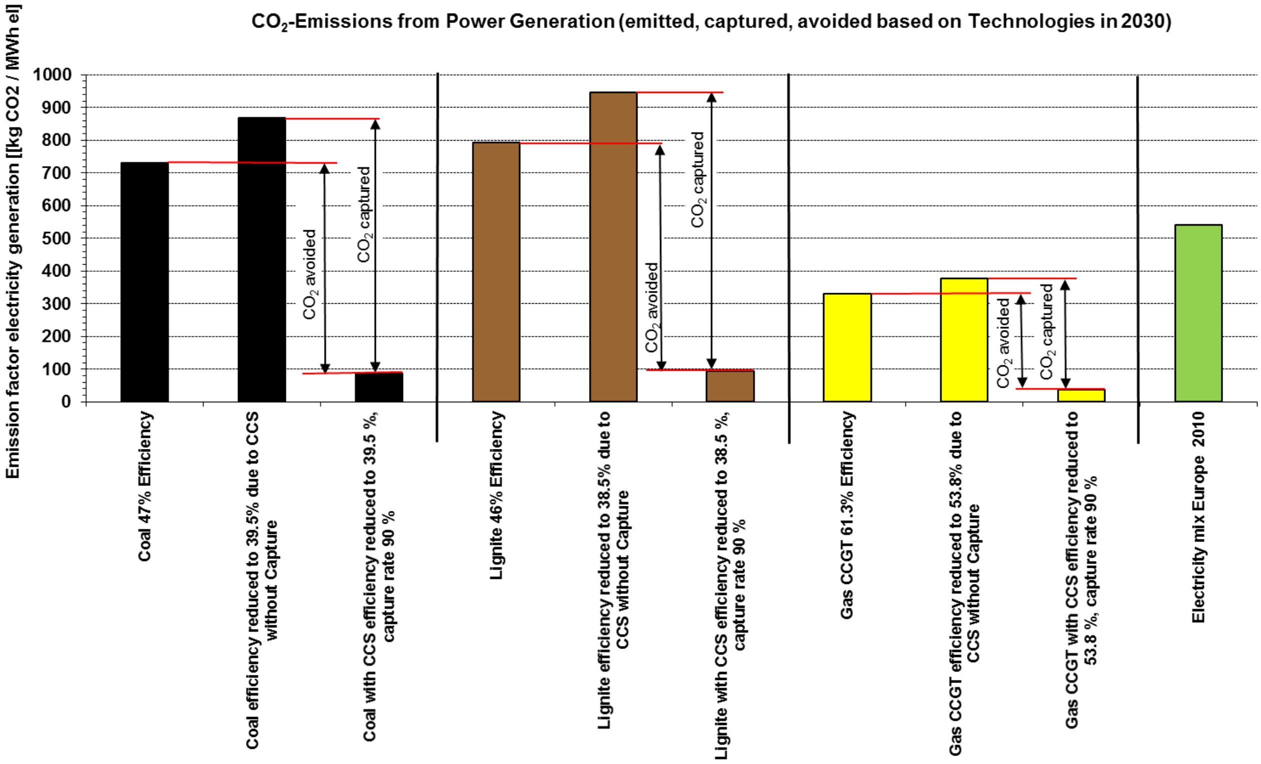

Figure 2: The difference between captured and avoided CO_2 for various types of power plants based on assumed efficiencies in 2030 *(Source: updated figure from Radgen et.al[7])*

Parameter	Unit	Reference	Post-comb. (BASE)	Post-comb. (OPTI)
Net capacity	(MWe)	736	616	616
Net efficiency η_{LHV}	(%)	46	38	38
Spec[8] CO_2 generation	(t_{CO2}/MWh)	0.759	0.918	0.918
Capture rate	(%)	-	90	90
Spec CO_2 emission	(t_{CO2}/MWh)	0.759	0.092	0.092
Spec CO_2 captured	(t_{CO2}/MWh)	-	0.826	0.826
Spec CO_2 avoided	(t_{CO2}/MWh)	-	0.667	0.667
Avoidance rate	(%)	-	87.8	87.8
Yearly captured	(Mt_{CO2}/yr)	-	3.82	3.82
Total investment costs	(M€)	1267	1762	1558
Levelised CAPEX cost	(€/MWh)	19.1	31.8	28.1
Levelised O&M + Fuel cost	(€/MWh)	29.1	41.1	38.7
Total LCOE	(€/MWh)	48.2	72.9	67.2
Cost of CO_2 avoided w/o T&S	(€/t_{CO2})		37.2	28.5

Table 1: Difference in costs between post-combustion and reference cases for BASE and OPTI plants for hard coal *(Source: ZEP[9])*

[7] Assessment of technologies for CO2 capture and storage. Research Report for the Federal Office of Environment, Germany, 2006: www.umweltbundesamt.de/publikationen/assessment-of-technologies-for-co2-capture-storage
[8] Specific = emissions per unit produced
[9] www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html

Data for key industrial sectors

a) Refineries

The sector
The EU has ~80 mainstream refineries operating in 2015, with an emissions profile that varies widely due to facility size, products produced, feed quality and complexity. Half of the refineries operating in the EU emit less than 1.3 Mt of CO_2 annually, roughly equivalent to a medium-scale, gas-fired power generation plant. In 2010, the refinery sector accounted for 14% of the EU's direct industrial emissions.

CO_2 emissions
Refineries are complex industrial sites that are highly integrated and characterised by diverse process configurations. Thus a single site will have numerous possible CO_2 emissions points. Crude oil is typically heated in a distillation column using fired heaters. Heavy components of the distillation process undergo further processing in a fluid catalytic cracker (FCC) to produce more gasoline and other light products, or in hydrocrackers to produce more diesel. Generally speaking, a refinery typically emits between 0.1 and 0.2 tonne CO_2 per tonne of crude processed for simple to medium conversion refineries; and up to ~0.3 tonne CO_2 per tonne of crude processed for complex refineries.[10]

CO_2 reduction options
Refineries can reduce their CO_2 emissions in three ways: by improving energy efficiency, fuel shift (using gas instead of liquid or solid fuels for operating the refinery) and deploying CCS. CCS could emerge as a key mitigation route for the refining sector when the other two options have been fully utilised.

The role of CCS
There will be no single 'CO_2 capture' solution applicable across the industry or to all facilities. Table 2 summarises the most important CO_2 emission characteristics of the various sources of CO_2 in refineries.[11]

Emitter	FCC refinery	Hydrocracker refinery	Typical CO_2 concentration
Process furnaces	44%	52%	3-12%
Utilities	36%	31%	3-12%
Hydrogen plant	-	17%	20-99% (depending on technology)
Fluid catalytic cracker	20%	-	8-12%

Table 2: CO_2 capture options for a refinery and their concentration of CO_2 (Source: Concawe[11])

CCS in refineries, with their numerous CO_2 emissions points, will require a suite of different technology solutions with differing costs of capture and varying time of deployment. Such solutions are dependent on the processes present at a particular oil refinery site and could vary from facility to facility.

- *Hydrogen production*, needed for the hydrocracker, creates CO_2 as an inherent part of the reaction process. The resulting CO_2 stream concentration after hydrogen purification is typically less than 50% and is recycled as a fuel to provide thermal energy for the reaction process, complementing the main natural gas fuel source. A small minority of older hydrogen plants use a hydrogen separation process that produces a high CO_2 concentration stream, but this represents a very small percentage of total refining CO_2 emissions and its impact for the purposes of this study is expected to be low.
- *Fluid catalytic cracking* (FCC) is often the single largest source of CO_2: ~18% of EU refining CO_2 emissions. The CO_2 concentration in the flue gas is much lower: 8% to 12%. Capturing it requires post-combustion capture equipment or a switch to oxy-firing concepts. However, capture costs are

[10] UNIDO refinery CCS roadmap: www.globalccsinstitute.com/publications/global-technology-roadmap-ccs-industry-sectoral-assessment-refineries
[11] Concawe: "The potential for application of CO2 capture and storage in EU oil refineries": www.concawe.eu/publications/376/40/The-potential-for-CO2-capture-and-storage-in-EU-refineries.

higher than for coal plants due to lower economies of scale and high retrofit installation costs.

- *Utilities and process heaters* create combustion derived emissions that produce the majority of CO_2 at refineries; however, the CO_2 is generally at low pressure and concentrations (3% to 12%, similar to power plants). They require the use of post-combustion capture equipment with lower economies of scale and high retrofit installation costs compared to power plants.

The cost
In European oil refineries, CO_2 capture would need to be retrofitted to existing emission sources, rather than new-build, which would result in higher equipment and installation costs than in a new-build configuration. The costs for CO_2 avoidance in a specific, complex refinery has been estimated by van Straelen et Al: Figure 3 below shows CO_2 emissions from various sources, while Figure 4 shows estimates of CO_2 capture costs for the six largest emitters.[12]

There is a clear distinction between emissions from the gasifier which can be abated for 30 €/t_{CO2} and the other emitters which are 90-120 €/t_{CO2}. However, it should be noted that this refinery is unusual because it has a gasifier feeding syngas to a hydrogen production plant. Only four EU refineries are equipped with such plants. Furthermore, this specific refinery produces a particularly high volume of high purity CO_2 because it is the only one of the four that does not combine the hydrogen production plant with a methanol production unit. Methanol production substantially reduces the available volume of high purity CO_2 because it converts carbon from the gasification process into methanol instead of CO_2. Costs for capturing the remaining 50% would be significantly higher since they originate from a multitude of small emission sources dispersed over the whole installation, leading to additional costs for transporting flue gas streams to a central capture unit. A more in-depth study on the application and costs of CCS for refineries is currently being carried out by a consortium comprised of the IEA GHG R&D Programme, SINTEF Energi and Concawe, with results expected by the end of 2016.

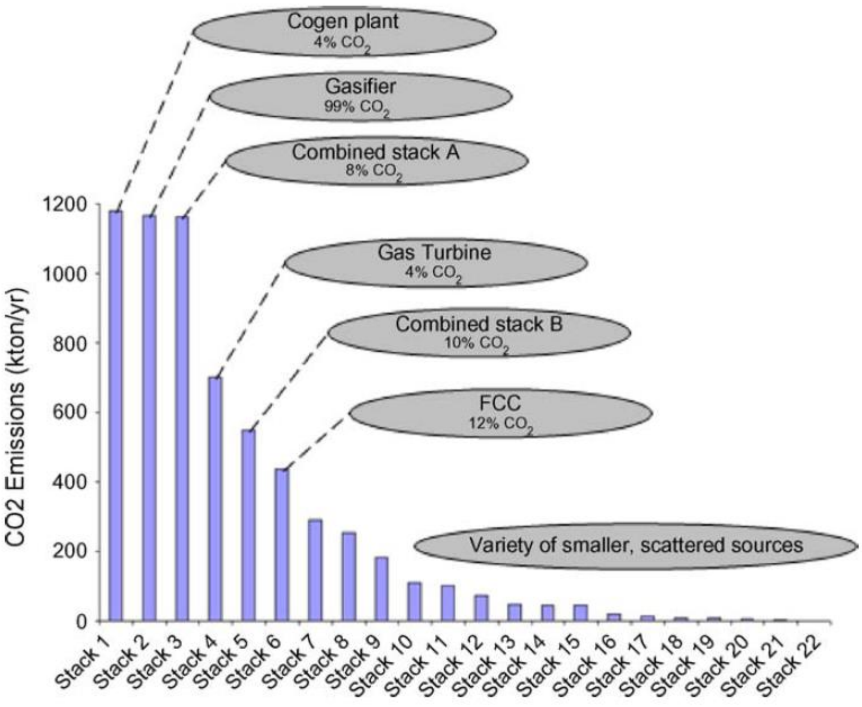

Figure 3: CO_2 emissions from point sources in a specific complex refinery (Source: van Straelen et Al)[12]

[12] "CO2 capture for refineries, a practical approach", International Journal of Greenhouse Gas Control 4 (2010) 316–320. See also footnote 11.

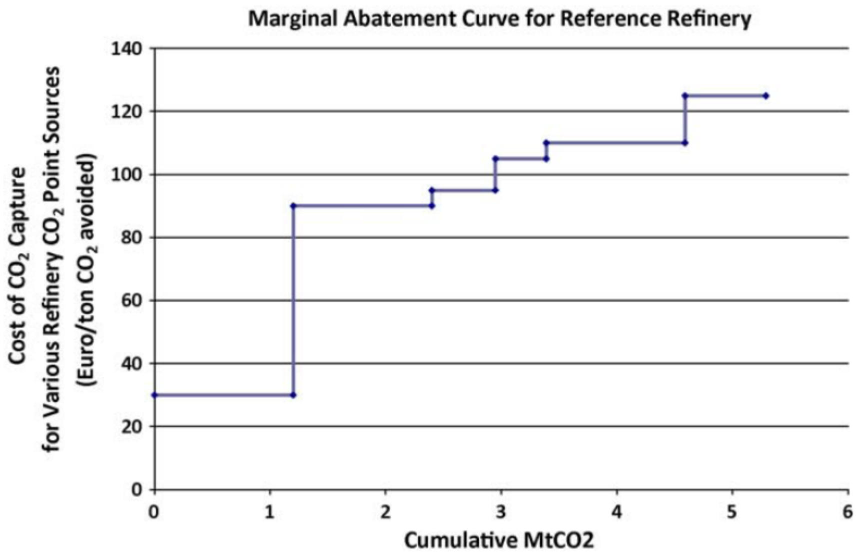

Figure 4: Marginal CO_2 capture cost curve from point sources in a specific, complex refinery (Source: van Straelen et Al)[12]

b) Steel production

The sector

Crude steel production has two main routes, either based on iron ore (via Basic Oxygen Furnace or BOF) or scrap (Electric Arc Furnace or EAF). This study focused on iron ore based production of Hot Rolled Coil (HRC) since the EAF emits only small amounts of CO_2 shared over many small operations. The EU accounts for ~10% of global steel production, split into 101 Mt BOF steel and 71 Mt EAF steel (2010). The average emission factor for BOF steel was 1.89 t_{CO2}/t_{HRC} which brings the total to 191 Mt_{CO2} for BOF steel in 2010, representing ~21% of EU27 industrial CO_2 emissions.

The industry directly employs over 360,000 people, representing 1.25% of employment in EU manufacturing and achieves an annual turnover of ~€170 billion. Although the energy efficiency of steel production has improved dramatically over the last 50 years, the production process of crude steel remains a carbon-intensive process due to need to use carbon for the chemical reaction of iron ore reduction.

CO_2 emissions

There are two leading processes for steel production in Europe:

- At an integrated steel mill, where iron ore is converted into crude steel using coke, fluxes and other additives. In the EU, 60% of crude steel is produced in ~40 integrated steel plants. These emit CO_2 as an unavoidable part of the conversion of iron ore to elementary iron. To this end, steel plants produce coke for the blast furnace and inject additional coal in the process to reduce the iron ore to iron. This chemical reaction produces large quantities of process gases that still contain carbon monoxide (CO) which need to be burned before release into the atmosphere due to its toxic nature. The heat of the combustion of CO into CO_2 is captured to produce steam and power which makes the integrated steel plant quasi self-sufficient in energy supply. In integrated steel mills, sinter and coke production, ironmaking and steelmaking are responsible for 80% to 90% of CO_2 emissions.
- Processing of scrap or other scrap alternatives in an electric arc furnace (EAF) to produce crude steel. Recycling of scrap uses up to 75% less energy compared to producing new steel from iron ore; however, this route is limited by the availability of scrap supply and quality requirements. Europe currently has one of the highest scrap recovery rates globally – almost 85%.

Figure 5 below shows the order of magnitude of CO_2 intensity for steel production worldwide.

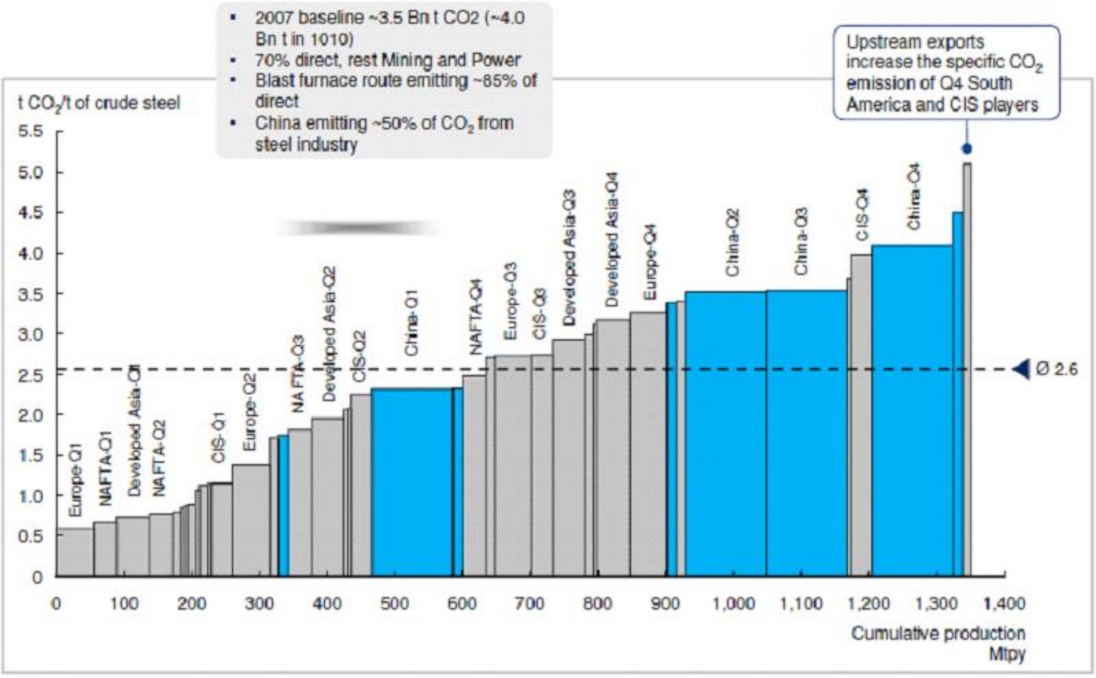

Figure 5: Overview of specific CO_2 emissions for steel production worldwide *(Source: ESTAD conference[13])*

CO_2 reduction options

Specific CO_2 emissions for Hot Rolled Coil (HRC) in $tonne_{CO2}$ have continuously decreased over recent decades. This has been achieved by continuous process improvements and to a large extent by increasing the size and productivity of the blast furnace which allowed the injection of more coal (instead of coke) and by increasing the oxygen enrichment (to reduce heat losses).

Many modern blast furnaces in Europe have been fully optimised to operate efficiently by minimising the use of fuel and reductants. Modern conventional blast furnaces in operation today are close to the theoretical achievable minimum and therefore have limited scope for further CO_2 reductions. Best practices for further reducing CO_2 emissions focus on further optimisation of the energy balance which could lead to ~15% reduction:

- Higher level of scrap recycling at the BOF steelmaking process by reducing thermal losses
- Increased utilisation of the different off-gases available on-site
- Various energy efficiency improvements and upgrades to the different iron and steelmaking processes, including the finishing mill.

The role of CCS

CO_2 Capture, Use and Storage (CCUS) has been recognised by the global steel community as an important option for reducing CO_2 emissions beyond the currently achievable 15%: the European steel community has led the Ultra-Low CO_2 Steelmaking (ULCOS Programme) since 2003. This has investigated a number of broad technological options which offer potential pathways for CO_2 reduction in the ironmaking process:[14]

- *Modification to the operation of the conventional blast furnace*: (ULCOS BF project). This involves the removal of the CO_2 from the blast furnace top gas and the recycling of the CO top gas into the blast furnace, instead of combusting the CO in an external power plant. The recycling of the CO would consequently reduce the coke consumption as less fresh carbon would be needed (~20-25%

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[13] 2014 European Steel Technology & Application Days (ESTAD) conference

[14] UNIDO steel roadmap: www.globalccsinstitute.com/publications/global-technology-roadmap-ccs-industry-steel-sectoral-report

reduction). The filtered CO_2 from the BF gas can be further purified to become CCS ready. This should achieve a 45-50% reduction in the CO_2 footprint per tonne of crude steel produced on the condition that the additional external power which needs to be purchased is CO_2 free.

- *Development of an alternative hot metal production process* (HIsarna project). This is a combination of two different technologies: 1) cyclone converter furnace (CCF) and 2) HiSmelt vessel. This ironmaking process allows the direct use of fine ore and non-coking coal, thereby eliminating sinter and/or pellet (agglomerating) and coke production plants, and reducing the number of CO_2 emission point sources within the site. HIsarna alone could reduce the CO_2 footprint of crude steel produced by 10-20%. As the process runs on oxygen, the output gas is rich in CO_2 and can be made CCS ready via cryogenic separation, which is expected to be more cost effective than an amine or (V)PSA capture route. Together with CCS, it could achieve a reduction of ~80% compared to the CO_2 footprint per tonne of crude steel produced via the BOF route. The HIsarna pilot plant at Tata Steel, The Netherlands, has operated four successful campaigns and is aiming for an endurance campaign in 2016. Important challenges are still ahead to scale up the pilot to a full industrial plant.
- *DRI-based steelmaking* (ULCORED project). This aims to Directly Reduce Iron (DRI) by reducing gas in a shaft, fixed bed or fluidised bed reactors running on oxygen. The iron-rich product (DRI) can be subsequently melted together with scrap in an EAF to produce crude steel. The DRI process could lead to a significant reduction in the CO_2 footprint of 20-25% for every tonne of crude steel produced compared to crude steel produced from the conventional BF-BOF route. The DRI process is currently not widely deployed in the EU due to high natural gas prices and lower energy efficiency vs. the coal-based BF process (+25% energy needs per tonne of steel). To date, no pilot project has been created to further develop the DRI process based on oxygen.
- *Future concepts may use renewable hydrogen* but this is still being studied at laboratory level.[15]

The cost

A cost estimation for a new build, integrated steel mill with CO_2 capture was undertaken in an IEA study.[15] The plant is assumed to be located along the Coastal Region of Western Europe. All costs are expressed in US$(2010, converted here at 1.34 US$/€ as stated in the IEA report). Two cases using amine-based post-combustion scrubbing were considered that lead to a 50% and 60% CO_2 avoidance rate, with avoidance costs (without T&S) of 55 and 60 €/t_{CO2}, respectively.

In order to understand the differences between cost estimates undertaken by the power and steel industries, key assumptions and results for ZEP's study are listed in Table 3 below. N.B. The output of the steel mill is a tonne of hot rolled coil (t_{HRC}); this unit takes the same role as MWh for power.

Again, the cost of CO_2 avoided (without T&S) is calculated as the difference in levelised cost divided by the difference in emission intensity (55.0 €/t_{HRC} = (487-430) €/t_{HRC}/(2.09-1.04) t_{CO2}/t_{HRC}). The increase in capital costs is mainly driven by the CO_2 capture and compression equipment, an additional steam generation plant for the stripper unit and a larger-sized power plant. However, CO_2 capture and compression dominates and accounts for an extra 506/682 M€ for 50/60% capture rate, respectively.

The 682 M€ (3760-3078) for 6.1 Mt_{CO2}/year may be compared with the 500 M€ for a BASE hard coal plant that captures ~3.8 Mt_{CO2}/year. The slightly higher specific costs for a coal plant can be explained by the lower CO_2 concentration in the flue gas stream compared to a steel mill. BASE technology is assumed to be state-of-the-art. Further cost reductions towards OPTI technology can also be expected for CCS on steel mills. As analysed in the same IEA study, a combination of the oxy-blast furnace (OBF) technology with an alternative solvent (MDEA) may reduce CO_2 avoidance costs (without T&S) down to 40-50 €/t_{CO2}. Such a development is assumed by applying a 1% cost reduction per year.

In summary, the costs for avoiding 50/60% of CO_2 emissions from an integrated steel mill are estimated to be 55/61 €/t_{CO2}, respectively.

[15] "Assessing the Potential of Implementing CO2 Capture in an Integrated Steel Mill", Volumes I and II

Parameter	Unit	Reference	Post-comb. (EOP-L1)	Post-comb. (EOP-L2)
Net capacity	(Mt_{HRC}/y)	4	4	4
Spec CO_2 generation	(t_{CO2}/t_{HRC})	2.09	2.283	2.362
Capture rate	(%)	-	54.4	64.9
Spec CO_2 emission	(t_{CO2}/t_{HRC})	2.09	1.04	0.83
Spec CO_2 captured	(t_{CO2}/t_{HRC})	-	1.243	1.532
Spec CO_2 avoided	(t_{CO2}/t_{HRC})	-	1.05	1.26
Avoidance rate	(%)		50	60
Yearly captured CO_2	(Mt_{CO2}/yr)	-	4.92	6.13
Total investment costs	(M€)	3078	3760	3971
Levelised CAPEX cost	(€/t_{HRC})	101	123	130
Levelised fuel & reductant cost	(€/t_{HRC})	88	113	122
Levelised additional costs	(€/t_{HRC})	241	251	254
Total levelised cost	(€/t_{HRC})	430	487	506
Cost of CO_2 avoided w/o T&S	(€/t_{CO2})	-	55.0	60.5

Table 3: Key study assumptions and results for steel production (Source: IEA[15])

c) Cement production

The sector

Cement production in the EU, which closely follows trends in the construction sector, has been negatively affected by the economic crisis. In 2007, total cement production in the 27 Member States reached a peak of 270 Mt (191 $Mt_{Clinker}$). In 2010, this had dropped to 190 Mt (142 $Mt_{Clinker}$), ~6% of global production. Regardless of the challenging economic conditions, four of the five largest cement producers – Lafarge (France), HeidelbergCement (Germany), Holcim (Switzerland) and Italcementi (Italy) – are based in Europe. In the EU, there are ~270 cement production plants and the sector employs 45,000 people directly.

CO_2 emissions

In 2010, CO_2 emissions from the cement industry in the EU totalled ~130 Mt_{CO_2}, representing 14% of EU27 direct industrial CO_2 emissions. Cement production is an energy-intensive process and generates substantial CO_2 emissions. The most energy-intensive component is generally referred to as clinker burning. This involves gradually heating calcium carbonate ($CaCO_3$) with small amounts of additives in a kiln to 1.450ºC. At ~900ºC, calcination begins and CO_2 starts to get released from the calcium carbonate. In the EU, ~80% of cement plants have CO_2 intensities of 0.80 to 1 $t_{CO_2}/t_{Clinker}$, depending on the type of plant and fuel used for combustion. The average performance of the 10% most-efficient installations in the EU cement sector is understood to be 0.77 $t_{CO_2}/t_{Clinker}$.

CO_2 reduction options

Specific CO_2 emissions in $t_{CO2}/t_{Clinker}$ have continuously decreased between 1990 and 2013 by ~9% within the EU.[16] This has been achieved by reducing combustion emissions due to increased energy efficiency and the increased utilisation of alternative fuels and clinker substitutes in cement blending. However, CO_2 emissions from the calcination process to produce the clinker are inherently unavoidable. The split of emissions between fuel component and calcination component is ~40-35% and ~60%-65%, respectively. Beyond the implementation of best available techniques (BAT), there are no breakthrough technologies foreseen for the improvement of thermal energy efficiency in the cement sector. The average heat consumption of the EU industry was 3.6 GJ/$t_{Clinker}$ in 2006 and it is understood that 3.2 GJ/t on a yearly basis is an engineering limit.

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[16] "Getting the Numbers Right" Database EU28: www.wbcsdcement.org/GNR-2013/EU28/GNR-Indicator_59cAG-EU28.html

Options for reducing emissions include:

- Increase in energy efficiency: there is still a number of relatively inefficient shaft, wet and semi-dry kilns, as well as grinding equipment, in operation worldwide. Retrofits, such as changing operational set-ups to a dry process, allow for significant increases in energy efficiency compared to (for example) a wet process which demands an energy input up to 5.5 GJ/$t_{Clinker}$. However, the potential is quite limited as today only 5% of the global clinker volume is still being produced in a wet or semi-dry process. Possibilities for improving electricity efficiency are also relatively limited as high investment costs and product quality demands impact economic feasibility and efficiency improvements. Potential measures to improve the overall efficiency of cement production include switching from long kilns to preheater/precalciner kilns, preheater and cyclone modifications, improved clinker coolers, waste heat recovery, oxygen enrichment technology and improved grinding equipment (e.g. deployment of vertical roller mills). However, beyond the implementation of best available techniques (BAT), there are no breakthrough technologies foreseen for the improvement of energy efficiency in the cement sector and efficiency improvement potential is rather limited, with an expected reduction to 3.3-3.4 GJ/$t_{Clinker}$ in 2030 and 3.2-3.3 GJ/$t_{Clinker}$ in 2050.
- Combustion of waste and biomass fuels in the kiln: conventional fuels in cement kilns are petcoke and coal, but alternative fuels include municipal waste and biomass. A cement plant in Brevik, Norway, utilises on average 25% biomass-based kiln fuel, achieving a carbon intensity of 0.76 t_{CO_2}/$t_{Clinker}$. The use of alternative fuels has significant potential to reduce CO_2 from fuel combustion due to their lower carbon content compared to fossil fuels and their biogenic fraction. However, there are availability issues with certain wastes and biomass next to technical issues due to the different and varying properties of alternative fuels that limit their utilisation.
- Increased use of clinker substitutes in cement blending: clinker can be blended with by-products such as fly ash from coal combustion or slags from the steel industry. Blended cements can be mixed with up to 65% slags or 35% fly ash, which then reduces the CO_2 intensity of the final product. However, this option is limited by the local availability of such substitutes and blended cements with a large non-clinker component are generally considered less favourable for building purposes.
- CCS: CCS can reduce emissions from both the calcination process and fuel combustion. The point sources at a cement plant with relatively high concentrations of CO_2 (14% to 33%) mean that post-combustion capture could be applied to the plant without disrupting the core process. If biomass is added to the fuel mix, a cement plant could even become CO_2 negative.

The role of CCS

Given that energy efficiency improvements, and fuel and clinker substitutions have in many cases been exhausted, only CCS can substantially reduce emissions from the production process – by up to 80%. There are several options in the field of post-combustion and oxy-fuel capture (pre-combustion technologies are unable to capture the CO_2 emissions from the carbonate decomposition during the calcination process):[17]

- *Post-combustion capture of CO_2* from the cement industry using solvents involves similar capture technologies to those in the power sector (e.g. amine scrubbing). They are currently regarded as the most commercially mature, with the advantage that they can be retrofitted to existing plants at low technical risk.
- A specific post-combustion capture route that could be used is *carbonate looping*. The low pressure flue gas of a conventional cement kiln is passed through a vessel whereby the CO_2 is adsorbed by calcium oxide (CaO) in a process known as carbonation, producing calcium carbonate ($CaCO_3$). The remaining (primarily CO_2-free) gas is then released. Next, the calcium carbonate is passed to a calciner, where CO_2 is released from the CaO sorbent which can then be recycled to the carbonation phase. This is a technology mainly developed in Europe. The major benefits of carbonate looping are the potential energy savings and reduced operating costs compared to other post-combustion capture routes such as amine scrubbing. Although this technology is at an early stage of development, preliminary investigations have estimated CO_2 avoidance costs lower than

[17] IEAGHG 2013: Deployment of CCS in the Cement Industry: www.ieaghg.org/docs/General_Docs/Reports/2013-19.pdf

conventional post-combustion capture systems, with minimum process efficiency losses of 5% to 8%. It is currently being assessed by the cement industry as a potential retrofit option for existing kilns and in the development of new oxy-firing kilns.

- *Oxy-fuel technology*: an alternative capture process that may be more cost-efficient, as studies by ECRA[18] and the IEA[17] indicate that thermal energy demand will only be minimally affected and energy consumption and costs will be lower than post-combustion capture using solvents. Here, the pre-calciner and kiln are heated by combusting the fuel in a controlled oxygen/CO_2 atmosphere. This would lead to a relatively high CO_2 concentration in the flue gas making purification relatively easy, while potentially increasing the thermal energy efficiency of the clinker burning process at the same time. The time horizon for operating industrial-scale oxy-fuel cement plants is 2025/2030, as application of this technology in the cement industry is still at the laboratory stage.

The cost

A cost estimation for a representative new-build cement plant has been undertaken in the IEA study.[17] A typical production capacity of 1 $Mt_{Clinker}$/year has been chosen, corresponding to 1.36 Mt_{Cement}/year. Various CCS options have been considered, both post-combustion and oxy-fired. The best case for a fully oxy-fired arrangement is reported here: this leads to 84% CO_2 avoidance, with avoidance costs **(without T&S)** of 40.9 €/t_{CO2}.

Main assumptions and results are shown in Table 4 below. Note that the output of the cement plant is a tonne of cement (t_{Cement}). This unit takes the same role as MWh for power. N.B. The definition of CO_2 avoidance costs includes indirect emissions. Due to the overall low emission intensity, this has little impact on the resulting value of 40.9 €/t_{CO2} (without T&S).

Parameter	Unit	Reference	Fully oxy-fired
Net capacity	(Mt_{Cement}/y)	1.36	1.36
Spec electricity requirement	(kWh/t_{Cement})	97	211
Related CO_2 emission (@ 0.2 t_{CO2}/MWh)	(t_{CO2}/t_{Cement})	0.019	0.042
Spec CO_2 generation (process)	(t_{CO2}/t_{Cement})	0.609	0.609
Spec CO_2 generation (sum)	(t_{CO2}/t_{Cement})	0.628	0.651
Capture rate	(%)	-	90
Spec CO_2 emission (process+electricity)	(t_{CO2}/t_{Cement})	0.628 (0.609+0.019)	0.103 (0.061+0.042)
Spec CO_2 captured	(t_{CO2}/t_{Cement})	-	0.548
Spec CO_2 avoided	(t_{CO2}/t_{Cement})	-	0.525
Avoidance rate	(%)	-	83.6
Yearly captured CO_2	(Mt_{CO2}/year)	-	0.75
Total levelised cost	(€/t_{Cement})	50.9	72.4
Cost of CO_2 avoided w/o T&S	(€/t_{CO2})	-	40.9

Table 4: Key study assumptions and results for the cement industry (Source: IEA[17])

Summary of cost assumptions

Figure 6 below summarises the cost assumptions used for this study:

- The EUA price rises from zero to 73 €/t_{CO2} in 2050, driving the deployment of low-carbon technologies in the model.

[18] ECRA 2009: ECRA CCS Project – Report on Phase II

- Transport and storage costs start at 20 €/t_{CO_2} and drop to 13 €/t_{CO_2} in 2050. (This follows calculations undertaken in the ZEP's previous study on transport and storage costs, see Figure 25.)[19]
- The costs of CO_2 avoided are also reported for the power sector and represent the costs of switching from one type of technology (lignite, hard coal or gas) to the same type with CCS. The figure does not show the cost of CO_2 avoided when switching from lignite to gas (or to wind and solar PV). The model does not use these curves directly but rather the investment costs as detailed in Annex II. The model is free to replace lignite with lignite with CCS, gas or any other technology – whichever minimises the total system costs.
- In terms of generation costs, gas with CCS can be competitive with coal and lignite with CCS, depending on the exact circumstances such as fuel prices and yearly operating hours. The higher cost of CO_2 avoided in Figure 6 is a result of gas having a lower carbon content (200 kg_{CO2}/MWh_{LHV} compared to 350-400 kg_{CO2}/MWh_{LHV} for coal and lignite).
- As shown above, the cost data for industry originated from a variety of sources. They generally differ in assumptions on technical and economical development of CO_2 capture technology and appear to be less optimistic than ZEP's assumptions for the power sector. Assumptions also differ in plant life, discount rate and load factor, quantities that are important for deriving the capital component of product costs.
- Cost reduction of CO_2 capture units for coal and gas plants were assumed in a previous ZEP report.[2] A similar cost reduction of 1%/year is assumed to be applicable to industrial CCS as well.

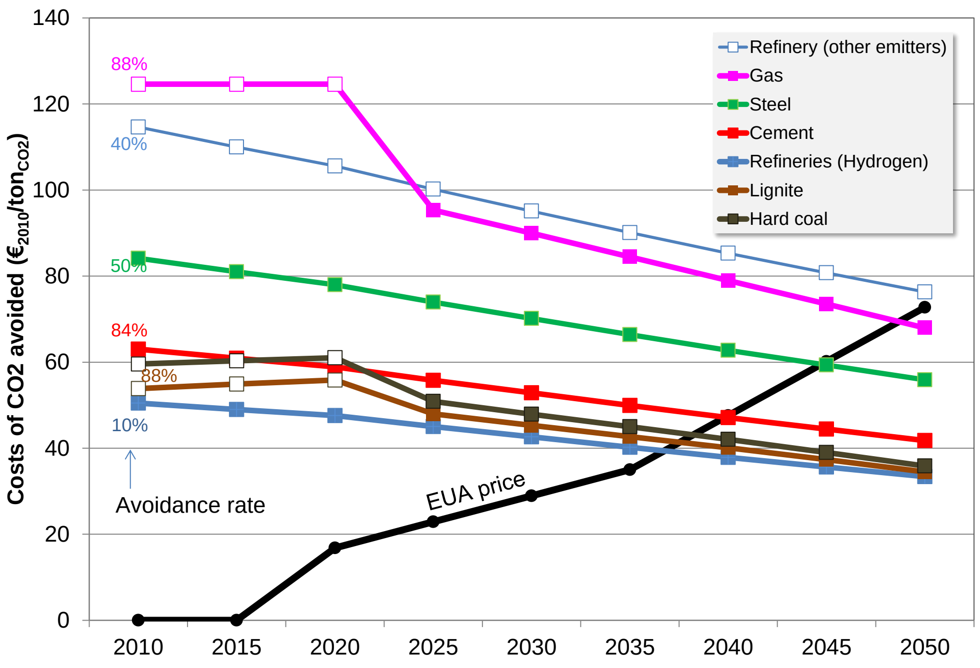

Figure 6: CO_2 emission price and CO_2 avoidance costs *(Source: ZEP)*

[19] www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html; www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html

3 The critical role of CCS clusters

Clusters will drive down the costs of CO_2 transport and storage

Figure 6 shows that CO_2 transport and storage costs represent a large portion of the total costs of CO_2 avoided. In line with previous ZEP reports,[2 3] a 500 km offshore pipeline of 20 Mt_{CO2}/year capacity, connecting onshore emitters to an offshore saline aquifer, was assumed (Figure 7).

Such an arrangement leads to 6 €/t_{CO2} transport costs (assuming 7,500 operating hours per year, 40 years lifetime and 8% interest rate).[20] With storage costs estimated at 14 €/t_{CO2},[21] this gives a total of 20 €/t_{CO2}, with a reduction to 13 €/t_{CO2} expected by 2050.

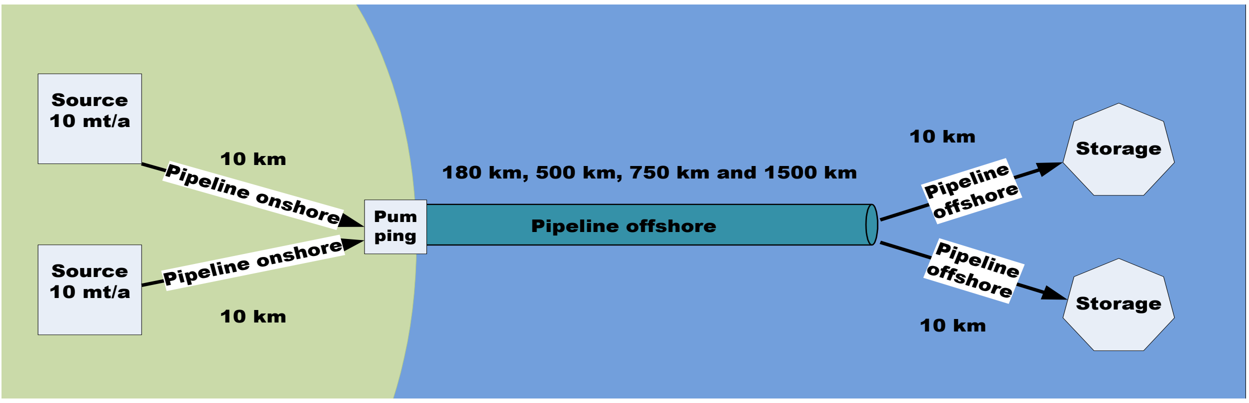

Figure 7: Assumptions for CO_2 transport and storage (Source: ZEP)

A large concentrated CO_2 source in power or industry emits ~5 Mt_{CO2}/year. The aforementioned 20 Mt_{CO2}/year therefore assumes a clustering of emitters, which represents the opportunity to reduce costs significantly.

The costs of CO_2 transport differ from project to project due to factors such as pipeline length, volumes of CO_2, corresponding pipe diameters, cost of labour and economic life of the infrastructure. These costs can be substantially reduced through economies of scale, i.e. by sharing a single CO_2 transport and storage infrastructure system. In particular for industries that emit lower quantities of CO_2, such a shared infrastructure is key to keeping costs at an acceptable level. Indeed, without such an infrastructure they would not be able to include CCS.

Many energy-intensive industries are already located in clusters

Clusters can therefore be expected to act as magnets for new CCS projects. De-risking investment for new entrants, they will promote the re-use of CO_2 as stockfeed and create a reliable supply chain of CO_2 for storage sites. This will not only lead to a reduction in CO_2 emissions, but promote regional industrial development.

A number of shared CO_2 transport networks are already being proposed, including Rotterdam in the Netherlands, and Teesside and Yorkshire/Humber in the UK. Indeed, in Europe and in other regions, many

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[20] www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html
[21] www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html

energy-intensive industries are already located in clusters. The availability of a CCS infrastructure should therefore be seen as a key building block for the transformation of such industrial clusters to a new low-carbon industry. The cost of *not* having clusters was considered in a previous ZEP report.[19]

To illustrate the effect of pipeline throughput, cost estimates from a study of onshore gas pipelines in the US were utilised: Figure 8 shows transport costs, normalised to a 20 Mt_{CO2}/year pipeline. Typical capture volumes for the different technologies have also been added for reference. Connecting each emitter separately increases transport costs significantly – by a factor of 2-5. This clearly illustrates the value of creating clusters of CO_2 emitters.

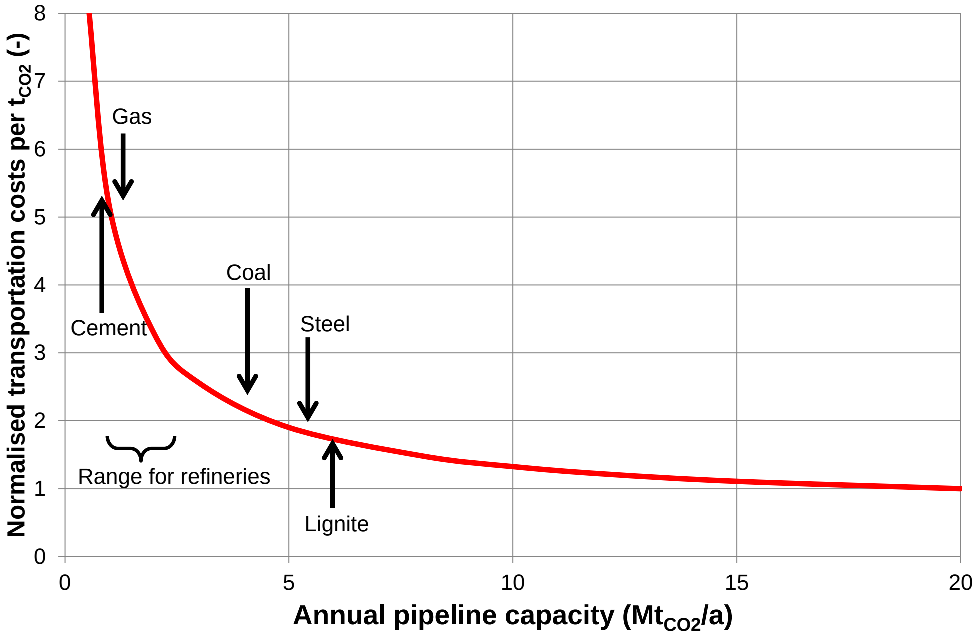

Figure 8: Reduction in specific CO_2 transport costs with throughput *(Source: www.ogj.com/articles/print/volume-109/issue-1/transportation/national-lab-uses-ogj-data-to-develop-cost-equations.html)*

4 Key features of the model

Incorporating both strategic and operational costs

The model[22] utilised by ZEP (and linked to the GCAM model) is a Stochastic Linear Optimization Problem (Figure 9). Its target: the minimisation of the total cost of supplying the European electricity system with sufficient energy to satisfy an exogenously given demand. It covers the period 2010-2050 in each country (node) of the EU, plus Norway and Switzerland.

The costs of the system, which are minimised by the model, encompass four sources: the first two being strategic, the other two operational:

1. Costs of investment in new generation capacity in each node and year
2. Costs of investment in new storage capacity. This is divided into power and energy which are handled largely independently.
3. Operative costs of generation which include, where appropriate, the cost of running the generators, emitting CO_2 and the costs of capturing and transporting the CO_2
4. Operative costs due to load shedding.

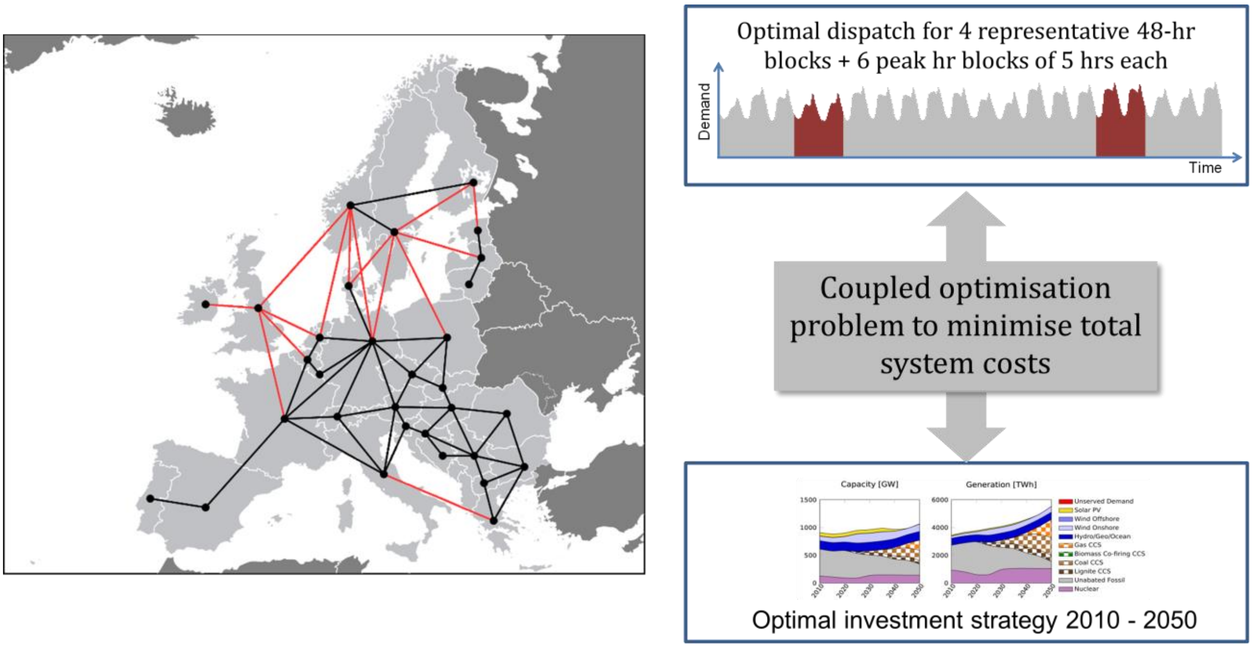

Figure 9: Overview of the model's characteristics and capabilities

Constraints in the model include limits on investment in generators and storage, balancing of the load in each node and at every hour, definition of flow between regions, limits on the ramp-up ability of certain technologies, and definition and operation of the storage alternatives (energy levels, charge, discharge and relationship to the node load balance).

[22] Known as the "EMPIRE" model (**E**uropean **M**odel for **P**ower system **I**nvestment with (high shares of) **R**enewable **E**nergy). For a full description see "The future European power system under a climate policy regime" in EnergyCon 2014, IEEE International Energy Conference, pp. 337–344, May 13–16, 2014: C. Skar, G. Doorman and A. Tomasgard. Dubrovnik, Croatia. DOI:10.1109/ENERGYCON.2014.6850446

The 'Industrial Emitters' add-on incorporates constraints in order to model the production of each industry (steel, cement and refineries), emission levels and limits per industry and node (upper limits are set to infinity by default), plus investment and operational costs.

Maximising accuracy with longer-time horizons

All previous simulations were carried out using 4 representative 48-hour blocks + 6 peak hour blocks of 5 hours each for the dispatch simulation. This may be considered sufficient for dispatchable power plants such as thermal coal or gas. However, fluctuating renewables show variations in time scales *beyond* two days. The model was therefore extended to cover two-week periods. Such an extension is especially important for seeking a better understanding of the value of electricity storage (Figure 10).

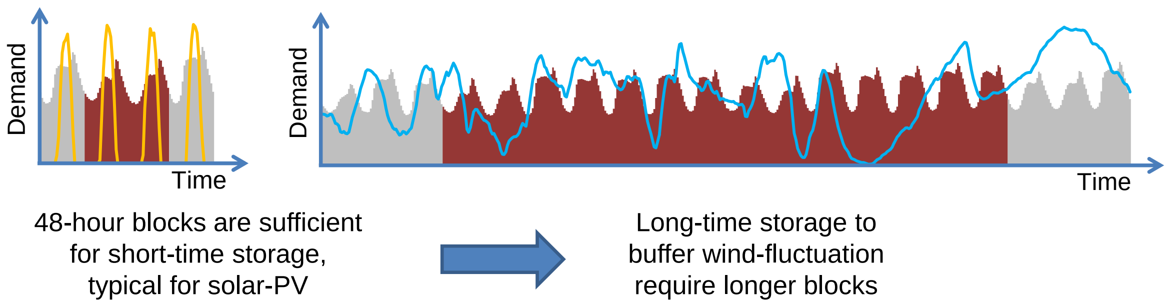

Figure 10: Extension of the modelling blocks

Assessing the role of electricity storage

The previous ZEP report[3] gave a first indication of the value of electricity storage. For scenarios where CCS is excluded, CO_2 reduction targets for the power sector must be met by a massive deployment of renewables – mainly PV and onshore wind. The model could only achieve this when all constraints on the amount of renewables were abandoned, a situation that may not be realistic due to the large area required.

Electricity storage adds value to the system towards the end of the simulation horizon by reducing curtailment on fluctuating renewable generation. The investment in storage is compensated by better utilisation of renewable generation, thereby leading to an actual cost reduction. The previous report assumed a generic storage technology, which shows technical characteristics similar to Adiabatic Compressed Air Energy Storage (A-CAES) or Pumped Hydro Storage (PHS). Here, two more technologies were added – battery and power-to-hydrogen-to-power.

The difference between these technologies is best described in terms of cost and round-trip (electrical to electrical) efficiency. Storage has two cost elements: a power related part that scales in €/kW (pumps, compressors, inverters etc.) and an energy-related part that scales in €/kWh (tanks, caverns, thermal storage, etc). The total installed costs are then determined by power costs + marginal energy costs x the number of storage hours. Table 5 below summarises the main assumptions for 2050 (see also Annex II).

N.B. Energy related investment costs should not be confused with the LCOE from a storage system: the LCOE depends on the number of cycles used by the storage system, which is an output of the dispatch optimisation in the model.

A battery storage of 3 hours will then cost 200 €/kW + 3 hours x 200 €/kWh = 800 €/kW. A high number of hours will soon no longer be economical due to high marginal energy costs. The low marginal energy cost of hydrogen will allow for longer-term storage and this may compensate for the lower round-trip efficiency.

Technology	Power cost (€/kW)	Marginal energy cost (€/kWh)	Round-trip efficiency (%)
Generic	600	60	72
Battery	200	200	70
Hydrogen	500	1	42

Table 5: A summary of the main assumptions for electricity storage in 2050

5 The results

Calculating the true costs of decarbonisation

In the previous ZEP report,[3] six different scenarios were modelled, resulting from a combination of different limits on solar PV and onshore wind, and different costs for PV. For the simulations reported here, however, only Scenario 6 was used. This assumes:

- No limits on the installation of PV and onshore wind
- A low installation cost of 200 $€_{2010}$/kW for PV in 2050.

Scenario 6 highlights the differences between a balanced mix of CCS and renewables, and an all-renewable scenario. However, such a low PV price will certainly require major technological breakthroughs: considering that the previously assumed 1,000 $€_{2010}$/kW in 2050 is a reality today in Germany for utility-scale PV, it does not seem unrealistic.

The GCAM 450 ppm scenario predicts an increase in electricity consumption of 60% from 2010 to 2050; such an increase can result from an electrification of transport and heating sectors. In order to challenge this assumption, a flat electricity demand was also considered.

The results of the modelling were evaluated in terms of investment and operating costs (variable and fixed operation & maintenance, fuel, EUAs and CO_2 transport and storage). A yearly cost is derived by adding operation costs and the costs of the investment. Here a WACC of 9% and a lifetime of 25 years were assumed, leading to an annuity of 10% on all investments undertaken up to that point:

$$\textit{Cost in year } i = 10\% \times \textit{Cumulated investments of years } 1 \textit{ to } i + \textit{Operation costs in year } i$$

The cumulated cost over the modelling period (2010 to 2050) is therefore the sum of all yearly costs:

$$\textit{Cumulated costs} = \sum_{i=1}^{n} \textit{Costs in year } i$$

The levelised cost of the product is the yearly cost divided by production:

$$\textit{Levelised product cost in year } i = \frac{\textit{Costs in year } i}{\textit{Production in year } i}$$

The absolute values for these quantities are not reported, only the difference to the business-as-usual (BAU) variant. This allows the modelling to quantify the true costs of decarbonisation – on top of the normal investments undertaken to operate and renew the installed base.

The deployment of CCS and RES is triggered in the model by an increasing CO_2 emission price (Figure 6). The electricity generation part of the modelling has significant complexity, since electrical demand can be satisfied by a variety of technologies with different CO_2 emission intensities, or by transmission across country boundaries. This leads to situations where electricity systems react to the increasing CO_2 price by first deploying highly efficient combined cycle power plants (CCPPs) and later, from 2030 onwards, CCS on coal (see previous ZEP reports [2 3]). However, the principle is always the same: CCS is deployed if the avoidance costs are less than the EUA price.

The situation is simpler for industrial emitters who basically have three options:

1. To emit CO_2 and pay the CO_2 price

2. To deploy CCS and sell free allowances
3. To shift production outside the EU when the ‘effective CO_2 cost’ for the industry in Europe is higher than the CO_2 costs in other regions for the same industry (i.e. the lack of a level playing field).

The model therefore needs to consider the free EUAs given to industries in order to maintain competitiveness with suppliers outside the EU. The CO_2 price is multiplied by the non-free EUAs (i.e. the portion that has to be purchased at that price). This leads to an additional CO_2 charge that increases product costs:

$$\boldsymbol{Additional\ CO2\ charge = CO2\ price \times (100\% - Percentage\ of\ free\ allowances)}$$

The decision logic of the model is therefore as follows: it deploys CCS when the CO_2 price exceeds CO_2 avoidance costs or when justified by support measures. If this condition is not met, CO_2 is emitted and the additional CO_2 charge is paid.

While not explicitly included in the model, it is also anticipated that industrial production will shift to outside the EU once the additional CO_2 charge exceeds the cost of that shift (including the one-time additional greenfield investment outside Europe and the additional transport and energy losses in bringing primary material (steel, clinker etc.) to European finishing plants).

Without CCS, EU CO_2 reduction targets cannot be met

The EU aims to reduce CO_2 emissions from power and energy-intensive industries by 80-95% by 2050. Assuming that the EUA price evolves according to the GCAM 450 ppm scenario, the modelling shows the conditions that must be met in order to meet these targets:

- An upfront public investment in CO_2 transport and storage infrastructure
- Support measures for both power and energy-intensive industries, conditional on the deployment of CCS.

The baseline scenario assumes that CCS is available once it is economical over the lifetime of the plant. The other variants model:

- A delay in CCS deployment to 2035
- CCS deployment for power only
- CCS deployment for industry only
- The unavailability of CCS
- The unavailability of large-scale electricity storage.

When CCS is available, the value of electricity storage is limited and therefore not shown. Figures 11-16 below include support measures for CCS (upfront public investment in CO_2 transport and storage + incentives for energy-intensive industries).

Figures 11 and 12 below show that **CO_2 reductions of 78% and 83%[23] are possible for an increasing and a flat electricity demand, respectively**. They show the extra cumulative costs that must be paid on top of a business-as-usual scenario, where the CO_2 price is zero. There are two sets of columns: one shows the effect on the power and industry sector, the other on society (where T&S infrastructure and incentives to energy-intensive industries are considered additional costs to society). N.B. These costs are not cumulative – they represent two different perspectives.

[23] As overall CO_2 emissions from European power decreased by ~18% between 1990 and 2010, this is equivalent to over 90% emissions reduction over 1990 levels

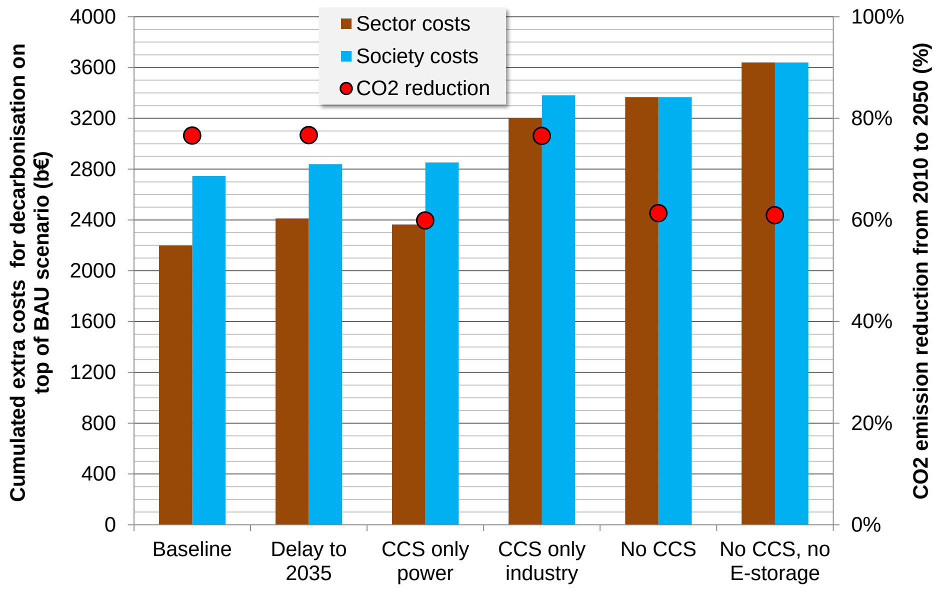

Figure 11: Extra cost of decarbonisation on top of BAU, cumulated from 2010 to 2050 (increasing electricity demand)

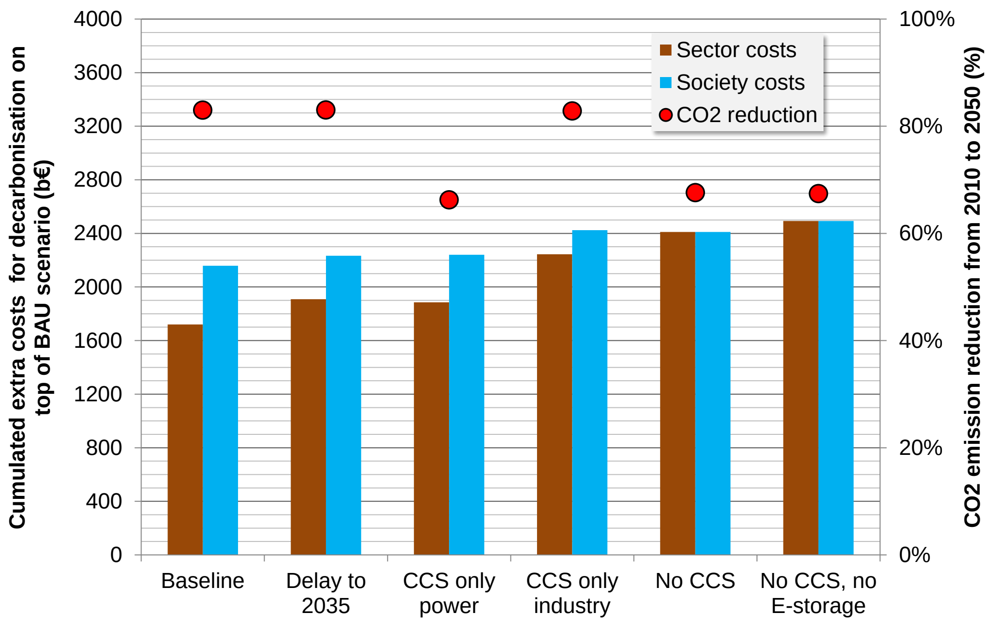

Figure 12: Extra cost of decarbonisation on top of BAU, cumulated from 2010 to 2050 (flat electricity demand)

"Delayed CCS" not only costs more, it is likely to result in "No CCS"

Figures 13 and 14 below illustrate these variants by showing the extra costs that must be paid on top of the baseline scenario. When the model delays CCS deployment to 2035, this costs power and industry sectors an extra 200 b€ and society an extra 100 b€ in order to reach EU CO_2 reduction targets of 80-95% by 2050.

This is mainly due to the extra deployment of renewables needed to compensate for the delay in CCS for power; all other variants lead to even larger extra costs.

Realistically speaking, however, such a delay would likely result in CCS not being deployed at all – costing at least €1.2 trillion extra to reach the EU's CO_2 reduction target for power by deploying other technologies. **The EU's target for industry, on the other hand, would not be achievable – in *any* scenario.**

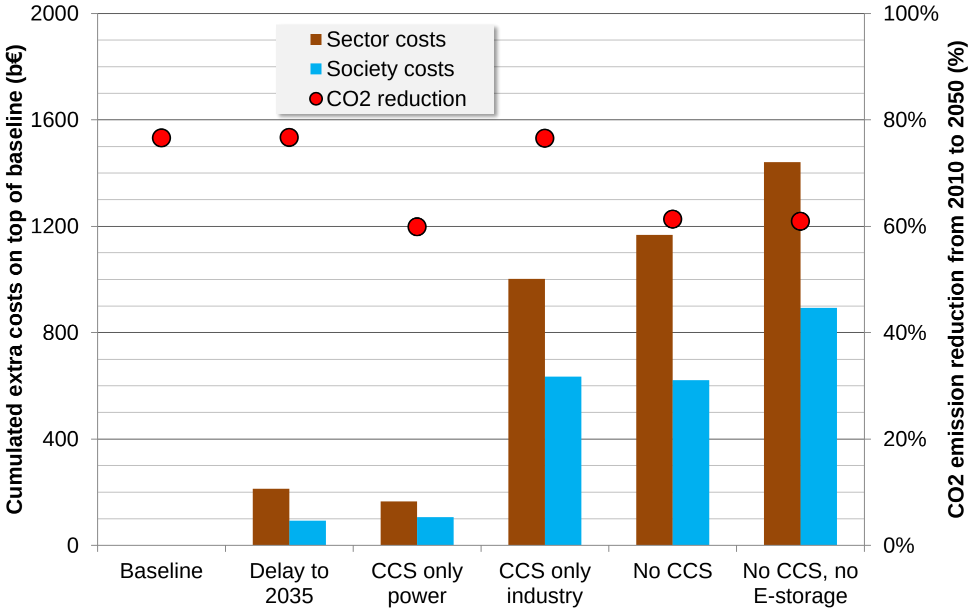

Figure 13: Extra cost on top of baseline (increasing electricity demand)

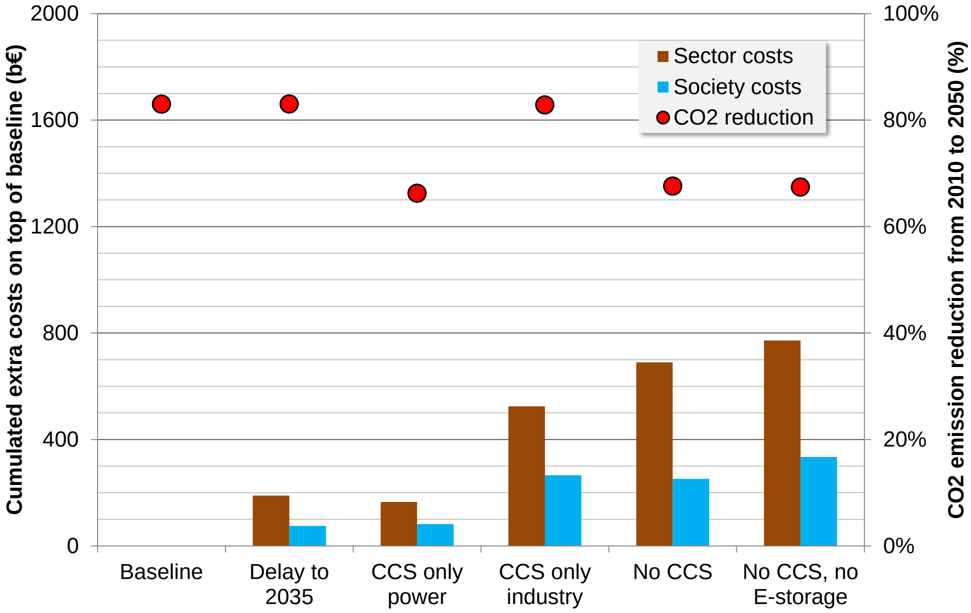

Figure 14: Extra cost on top of baseline (flat electricity demand)

Figures 15 and 16 below show the amount of CO_2 emitted and stored every year: CCS starts in 2025 with ~100-200 Mt_{CO2}/year, mainly from the power industry. The cumulated stored CO_2 within the modelling horizon of 2010 to 2050 amounts to 30 and 22 Gt_{CO2} for increasing and flat electricity demand, respectively.

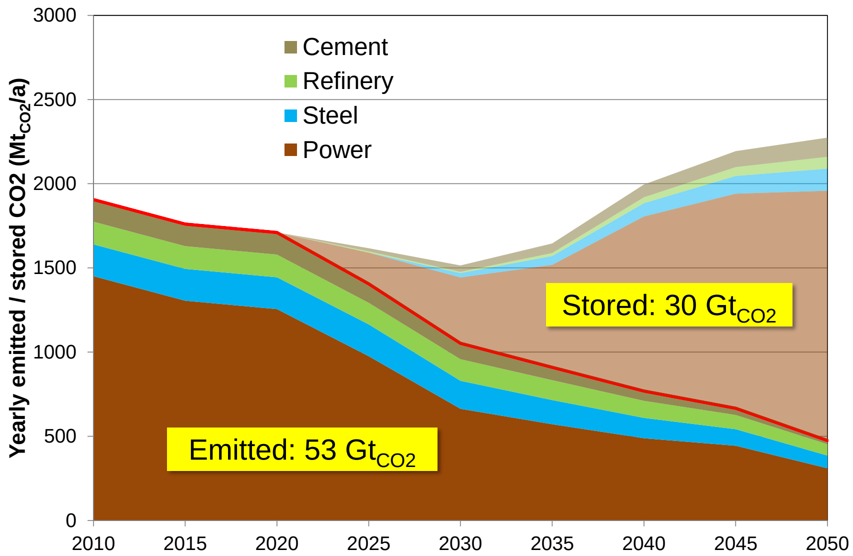

Figure 15: Emitted and stored CO_2 for power and industry (increasing electricity demand)

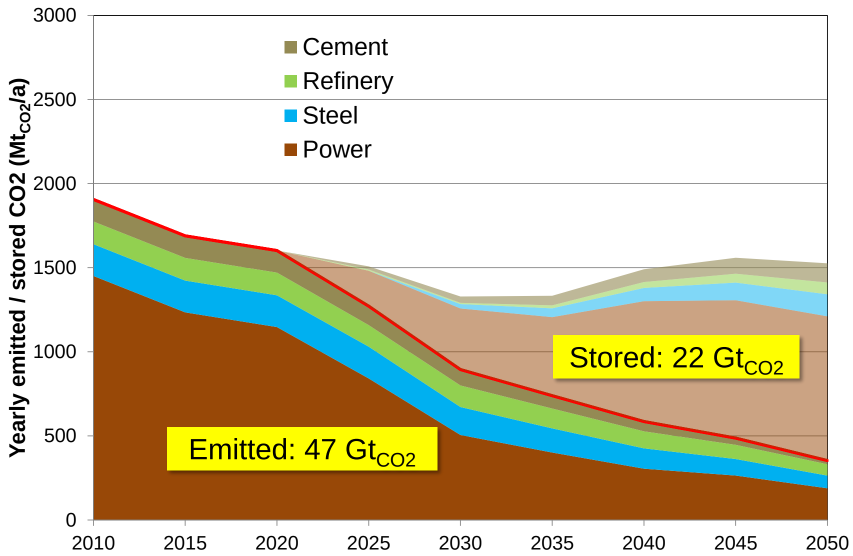

Figure 16: Emitted and stored CO_2 for power and industry (flat electricity demand)

The model also simulated the absence of supporting measures (public investment in transport and storage infrastructure, incentives to deploy CCS in energy-intensive industries). Figure 17 below shows that this would **delay the deployment of CCS to 2040, with a CO_2 reduction of only 68% – well below EU targets for power and industry**. All the simulations assume a clustering of CO_2 emitters that feed into a typical 20 Mt_{CO2}/year pipeline and storage site. **If such clustering is not realised, extra costs amount to 200-300 b€.**

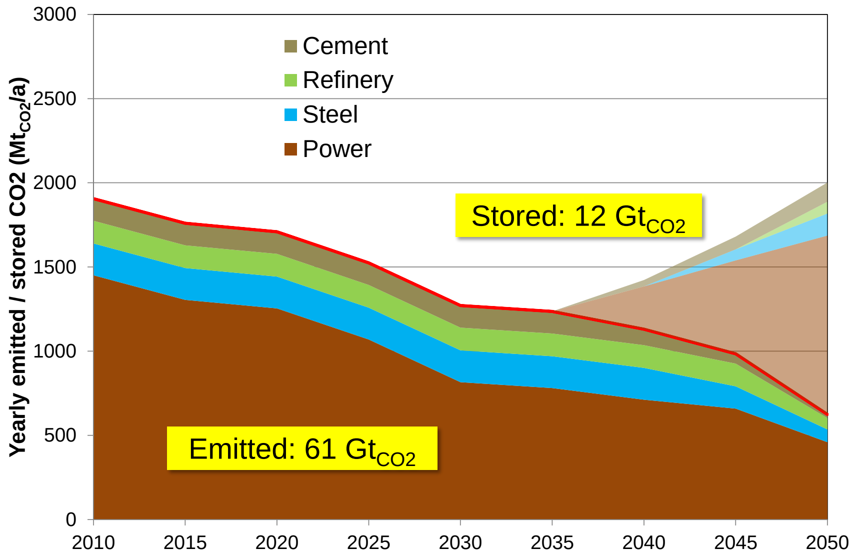

Figure 17: Emitted and stored CO_2 for power and industry (increasing electricity demand); no supporting measures

Including CCS leads to the lowest possible costs

Figures 18-20 below show the time evolution of **specific product costs (power, steel, cement) that must be paid on top of a business-as-usual case**, for which the CO_2 price is zero. (No such graphs have been produced for refineries because they produce a suite of different products.) The results for the power sector illustrate that including CCS in the generation mix leads to the lowest possible costs based on the assumed CO_2 price development; *not* having CCS available leads to extra generation costs of 16 €/MWh, while *not* having electricity storage to support renewables leads to extra generation costs of 7 €/MWh. N.B. When CCS is available, the value of electricity storage in reducing decarbonisation costs is limited and therefore not shown.

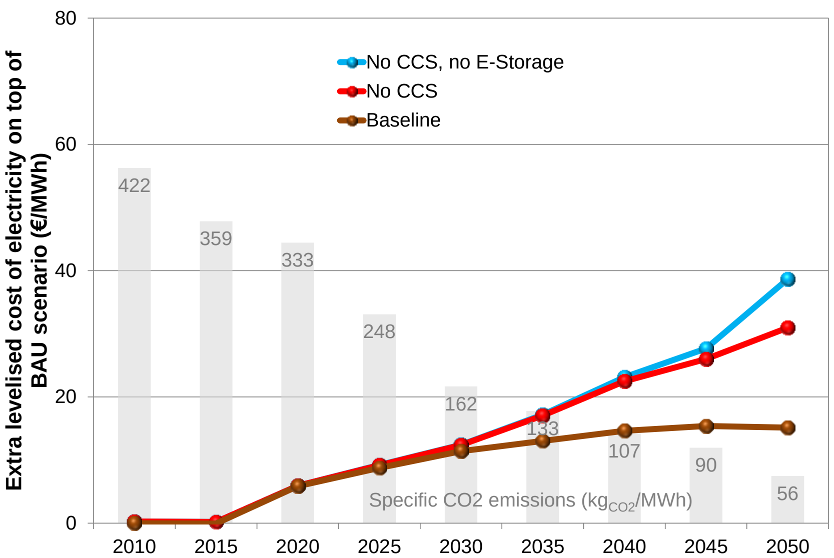

Figure 18: Extra levelised cost of electricity on top of BAU scenario (200 €/kW_{PV} in 2050)

Figure 19 below shows the situation for the steel industry, where it is assumed that free EUAs are cut by 1.7 %/year up to 2020 and by 2.2%/year from 2020 onwards:

- In 2050, 91% of the EUAs would have to be purchased; only 9% are free.
- The red curve shows the increase in product costs if no countermeasures are taken; the blue curve shows how this charge could be reduced by deploying CCS.
- The green curve shows the extra costs where supporting measures are applied (upfront public investment in T&S infrastructure + incentive of 30 €/t_{CO2} conditional on CCS deployment).
- Steel industry estimates that a shift in production to outside the EU would result in extra product costs of 50 €/t_{HRC} (additional investment in greenfield plant outside Europe vs. continued brownfield upgrade investments in Europe + additional transport/energy costs). The supporting measures would effectively avoid such a displacement. N.B. These measures will have a further positive effect on the climate since emission intensity outside the EU is ~0.5 t_{CO2}/t_{HRC} higher.

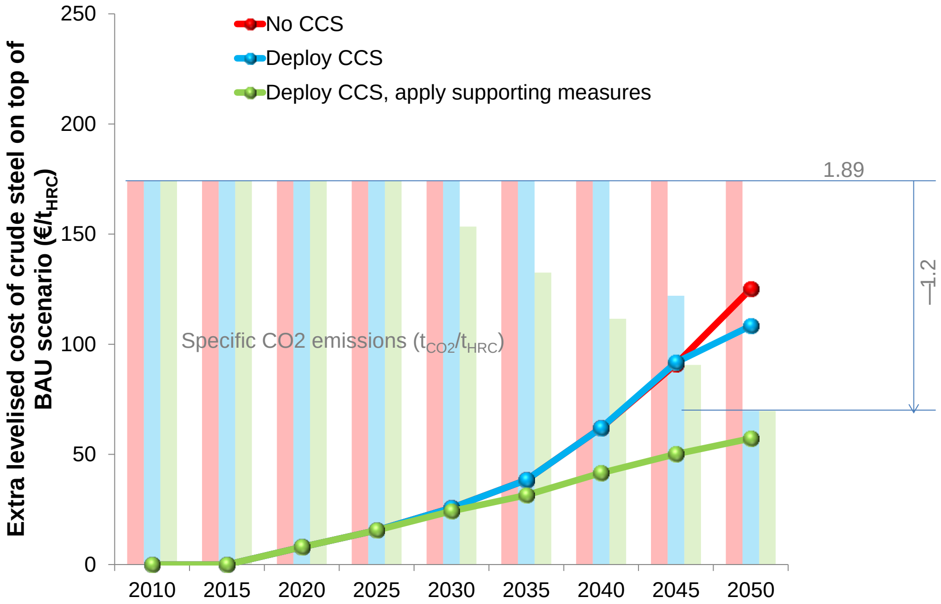

Figure 19: Extra levelised cost of crude steel on top of BAU scenario (baseline cost is 430 €/t_{HRC})

Figure 20 below shows the situation for the cement industry using the same reduction in free EUAs as for steel:

- The red curve shows the increase in production costs if no countermeasures are taken; the blue curve shows how this charge could be reduced by deploying CCS.
- The green curve shows the extra costs where supporting measures are applied (upfront public investment in T&S infrastructure + incentive of 15 €/t_{CO2} conditional on CCS deployment).

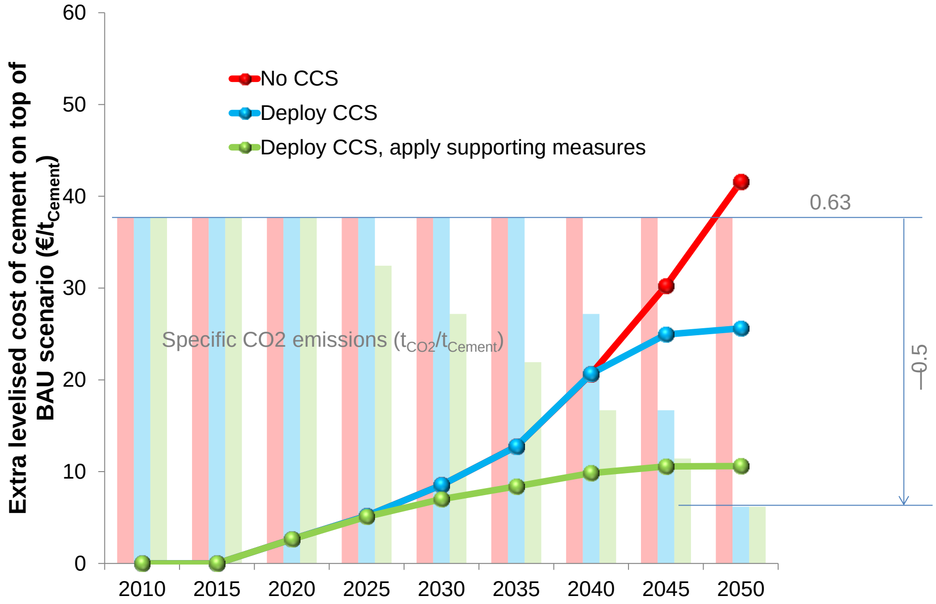

Figure 20: Extra levelised cost of cement on top of BAU scenario (baseline cost is 50.9 €/t_{Cement})

This illustrates the importance of an ETS with effective protection against carbon leakage. The current implementation of the ETS, with a phasing out of this protection, will not only lead to the de-industrialisation of Europe, but an increase in global CO_2 emissions. A revised ETS policy which promotes CCS over the displacement of production for energy-intensive industries is therefore urgently required – together with the supporting measures outlined above.

2015-2025 is a critical period for CCS deployment

Figures 21 and 22 below show the extra yearly investment required to deploy CCS in the baseline scenario for an increasing and flat electricity demand, respectively. Again, it must be emphasised that these investments relate to the **decarbonisation** of the European power and industry sectors, i.e. they are *in addition to* investments required to renew the production base in a business-as-usual scenario.

2015-2025 is a critical period for CCS deployment and investments in 3-6 clusters, each with 20 Mt_{CO2}/year capacity, are urgently needed to kick-start CCS. This requires 6-12 b€ investment – 3-6% of the total investment in T&S capacity required for Europe.

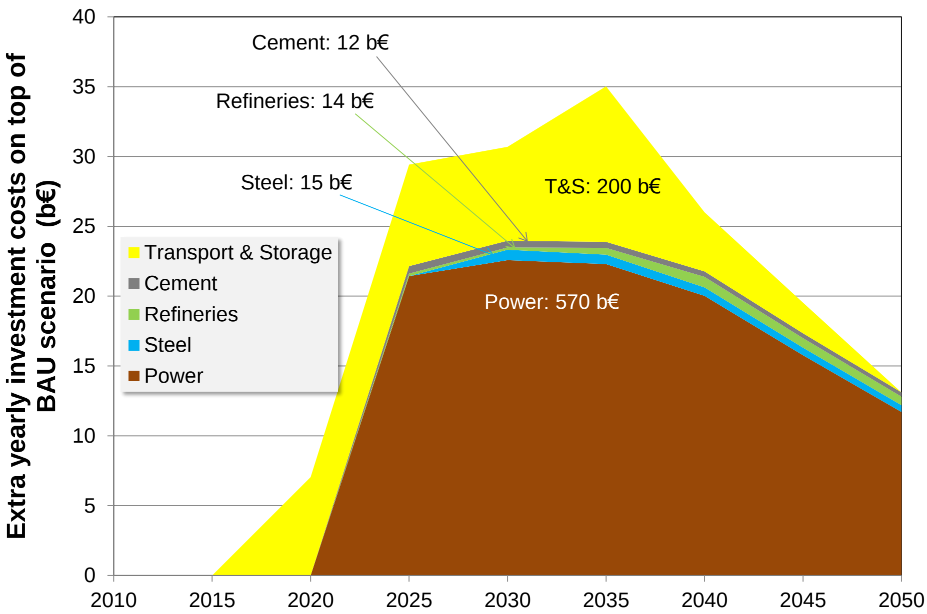

Figure 21: Extra yearly investment costs on top of BAU scenario to deploy CCS (increasing electricity demand)

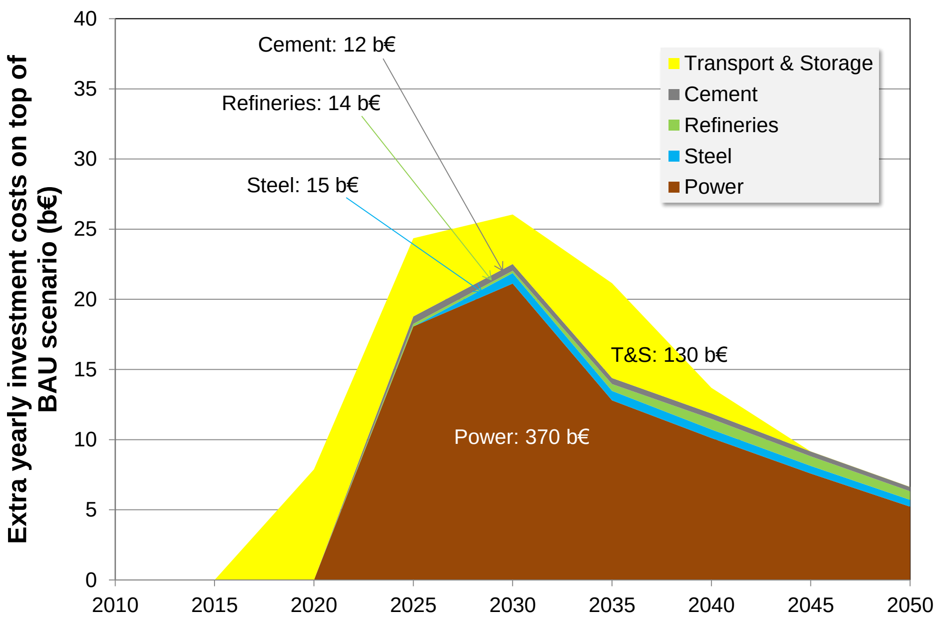

Figure 22: Extra yearly investment costs on top of BAU scenario to deploy CCS (flat electricity demand)

Electricity storage will not reduce the need for CCS

Electricity storage is modelled by prescribing a round-trip (electrical-to-electrical) efficiency, a cost portion that is proportional to power (€/kW) and a cost portion proportional to energy (€/kWh). The model is free to choose the power and energy independently. This is equivalent to choosing power and the number of storage hours.

Figure 18 illustrates the value of electricity storage in reducing power generation costs in 2050 for scenarios *without* CCS. Figure 23 below compares the previously used generic storage model with battery and hydrogen storage. This shows that hydrogen storage is as effective in capping costs as generic storage; battery storage is far less effective. When CCS is available, however, the value of electricity storage in reducing decarbonisation costs is limited.

The model chose ~8 hours' storage for both the generic and hydrogen storage, and 3.5 hours for battery storage. This leads to fully installed costs of 1,080 €/kW for generic storage, 508 €/kW for hydrogen storage and 900 €/kW for battery storage. Batteries could be as effective as generic storage in preventing curtailment; however, 8 hours' storage would cost 1,800 €/kW which is considered too expensive by the model. Generic and hydrogen storage have the same effect, but in this case the higher costs of generic storage are compensated by the higher efficiency.

Simulations with a longer-time period confirmed these results. No difference could be observed in terms of hydrogen storage, probably due to the fact that PV is the dominating technology that shows a diurnal pattern, which does not require longer-term storage.

N.B. The model aims to achieve a macroeconomic cost optimum, whereas the deployment of distributed battery storage may be driven by consumer prices and the desire to maximise self-consumption of locally produced PV electricity.

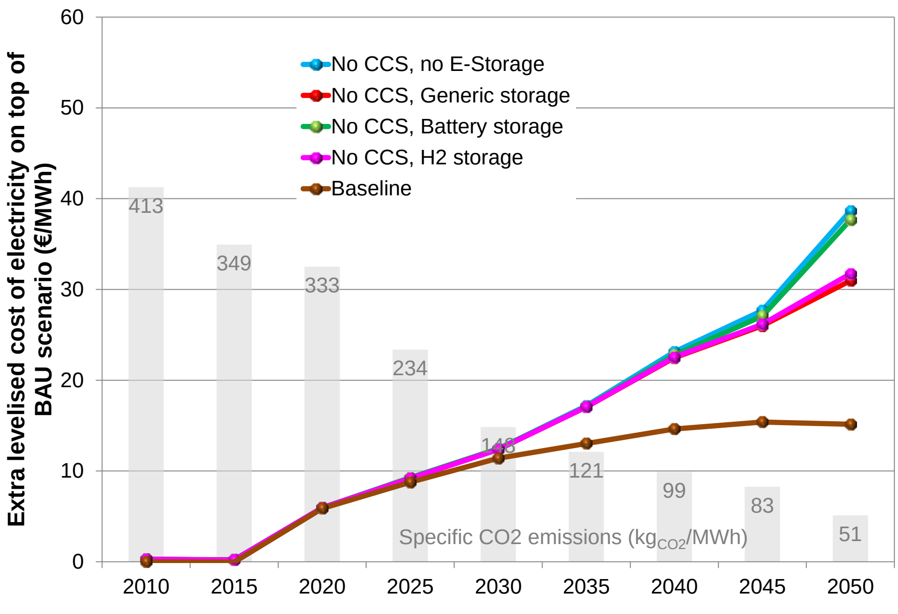

Figure 23: Extra levelised cost of electricity on top of BAU scenario for various storage options

Results are robust to variations in the assumptions

In Annex II we show the assumptions in detail, including the Operation and Maintenance costs of each technology out to 2050. In the earlier reports we undertook sensitivity calculations to assess if the various cost assumptions such as gas price, solar PV, or land area available for onshore wind, affected the broad conclusions of the studies. The sensitivities were bold in the cost assumptions that we took. For instance we reduced the capex cost of PV by a factor of 5 compared to the previously assessed technology costs. In January 2016 the team was asked by the ZEP Advisory Council to conduct further sensitives of the results to the O&M cost of Solar PV. The O&M costs in 2050 were reduced from 26 €/kW/a to 19.5 €/kW/a and 13 €/kW/a (see also Figures 27 and 28). The effect is to shift the optimisation to build more PV and less other technologies. The change does not affect the principle conclusion of the report that adding CCS to the mix leads to the lowest cost option to achieve the emissions targets by 2050. Not having CCS available will increase the cumulative costs by 1-1.2 trillion Euro, depending on the assumed O&M costs for Solar PV. These sensitivities demonstrate that the importance of a mix of technologies including CCS on Industrial and Power emitters is robust to variations in the assumptions. The effect was to change the absolute numbers for PV deployment but not the trends or conclusions.

It is pointed out that the aforementioned cost benefits of CCS are in fact smaller in magnitude than those of other studies for instance by the IEA (ref). We perceive that the reason for this is the 5 times reduction factor in the capital cost of PV to 2050 that we put in at the request of the European Commission. We did this to ensure that the modelling was assessing the cost in intermittency and integration and not adversely assessing the cost of technologies such as PV and wind.

Annex I: Emission volumes from industry

This report considers CO_2 emissions from crude steel production in oxygen-blown converters, taken for 2013 from the World Steel Association. The emission intensity is assumed to be an average of 1.89 t_{CO2}/t_{HRC}.

Country	Crude steel production (Mt_{HRC}/year)	CO_2 emissions (Mt_{CO2}/year)
Austria	7.288	13.77
Bosnia H	0.721	1.36
Belgium	4.738	8.95
Bulgaria	0	0
Switzerland	0	0
Czech R	4.805	9.08
Germany	29.185	55.16
Denmark	0	0
Estonia	0	0
Spain	4.21	7.96
Finland	2.22	4.20
France	10.19	19.26
Great Britain	9.915	18.74
Greece	0	0
Croatia	0	0
Hungary	0.744	1.41
Ireland		0.00
Italy	6.8	12.85
Lithuania	0	0.00
Luxembourg	0	0.00
Latvia	0	0.00
Macedonia	0	0.00
Netherlands	6.58	12.44
Norway	0	0.00
Poland	4.399	8.31
Portugal	0	0.00
Romania	1.625	3.07
Serbia	0.396	0.75
Sweden	2.986	5.64
Slovenia	0	0.00
Slovakia	4.172	7.89
TOTAL	**100.974**	**190.84**

CO_2 emissions for the refinery sector are taken for 2013 from the European Pollutant Release and Transfer Register.

	CO_2 emissions (Mt_{CO2}/year)
Austria	2.83
Bosnia H	-
Belgium	5.92
Bulgaria	1.14
Switzerland	0.96
Czech R	0.77
Germany	22.68
Denmark	0.93
Estonia	0.00
Spain	10.54
Finland	3.22
France	11.75
Great Britain	12.23
Greece	5.31
Croatia	-
Hungary	1.40
Ireland	0.29
Italy	18.46
Lithuania	0.00
Luxembourg	0.00
Latvia	0.00
Macedonia	-
Netherlands	10.25
Norway	4.53
Poland	1.69
Portugal	3.70
Romania	2.26
Serbia	0.00
Sweden	2.57
Slovenia	0.00
Slovakia	1.42
TOTAL	**124.86**

CO_2 emissions for the cement sector are taken for 2013 from the European Pollutant Release and Transfer Register.

	Cement production (Mt_{Cement}/year)	CO_2 emissions (Mt_{CO2}/year)
Austria	4.5	2.8
Bosnia H	0.0	-
Belgium	11.0	6.9
Bulgaria	2.6	1.6
Switzerland	4.1	2.6
Czech R	4.3	2.7
Germany	41.1	25.8
Denmark	2.6	1.7
Estonia	1.2	0.8
Spain	20.0	12.6
Finland	1.5	0.9
France	23.3	14.7
Great Britain	11.1	6.9
Greece	9.3	5.8
Croatia	0.0	-
Hungary	1.8	1.1
Ireland	3.1	2.0
Italy	23.3	14.7
Lithuania	1.5	1.0
Luxembourg	1.0	0.6
Latvia	1.2	0.8
Macedonia	0.0	-
Netherlands	0.8	0.5
Norway	2.1	1.3
Poland	16.0	10.1
Portugal	7.1	4.4
Romania	6.7	4.2
Serbia	0.0	0.0
Sweden	4.4	2.8
Slovenia	1.1	0.7
Slovakia	3.1	2.0
TOTAL	**209.6**	**131.6**

Annex II: Cost assumptions

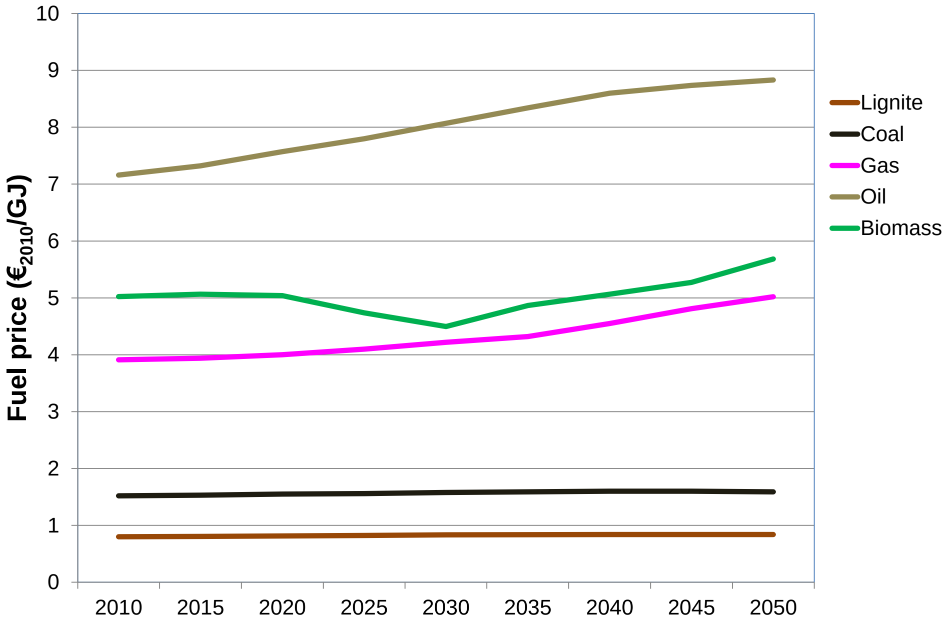

Figure 24: Fuel prices for the GCAM 450 ppm scenario

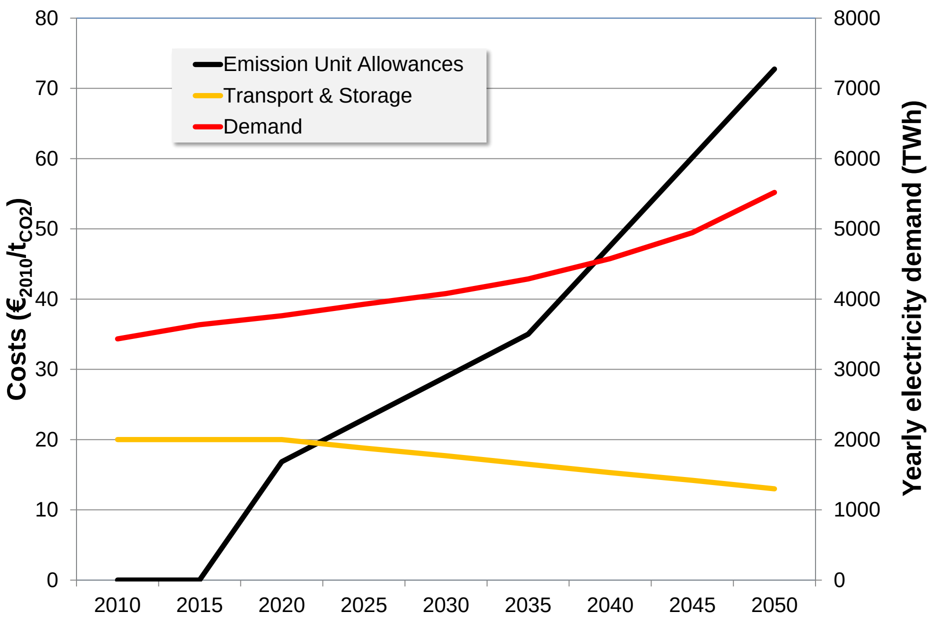

Figure 25: Cost assumptions and yearly electricity demand for the GCAM 450 ppm scenario

Technology 2010	Investment costs (€/kW)	(€/kWh)	Lifetime (years)	Fixed O&M (€/kW/a)	Variable O&M (€/MWh)	Efficiency (%)
Lignite existing	0		40	32.40	0.48	0.351
Lignite	1600		40	32.40	0.48	0.430
Lignite CCS	0		0	0.00	0.00	0.000
Lignite CCS support	2600		40	79.65	1.18	0.310
Coal existing	0		40	31.05	0.46	0.374
Coal	1500		40	31.05	0.46	0.450
Coal CCS	0		0	0.00	0.00	0.000
Coal CCS support	2500		40	78.30	1.16	0.330
Gas existing	0		30	19.50	0.45	0.480
Gas OCGT	400		30	19.50	0.45	0.400
Gas CCGT	650		30	30.38	0.45	0.601
Gas CCS	0		0	0.00	0.00	0.000
Gas CCS support	1350		30	77.63	1.16	0.480
Oil existing	0		40	19.50	0.00	0.376
Bio existing	0		40	48.36	0.00	0.382
Bio 10% co-firing	1600		40	32.40	0.48	0.450
Bio 10% co-firing CCS	0		0	0.00	0.00	0.000
Nuclear	3000		60	134.46	1.80	0.360
Wave	6050		25	153.85	0.00	0.330
Geothermal	5500		40	92.31	0.00	0.800
Hydro regulated	3000		60	125.00	0.00	1.000
Hydro run-of-the-river	4000		60	125.00	0.00	1.000
Hydro pumped storage	1250		60	108.00	0.00	1.000
Wind onshore	1200		25	54.40	0.00	1.000
Wind offshore	4080		25	137.97	0.00	1.000
Solar PV	1900		25	19.50	0.00	1.000
Solar PV (low)	1900		25	19.50	0.00	1.000
Generic storage	800	80	25	50.00	1.00	0.700
Battery storage	300	500	10	15.00	0.00	0.700
Hydrogen storage	1000	1	15	0.00	0.00	0.380

Figure 26: Technology cost and performance assumptions for 2010 (CCS support refers to early demonstration projects)

Technology 2030	Investment costs (€/kW)	(€/kWh)	Lifetime (years)	Fixed O&M (€/kW/a)	Variable O&M (€/MWh)	Efficiency (%)
Lignite existing	0		40	32.40	0.48	0.360
Lignite	1600		40	32.40	0.48	0.460
Lignite CCS	2530		40	50.04	3.28	0.385
Lignite CCS support	2600		40	79.65	1.18	0.310
Coal existing	0		40	31.05	0.46	0.383
Coal	1500		40	31.05	0.46	0.470
Coal CCS	2430		40	45.85	2.46	0.395
Coal CCS support	2500		40	78.30	1.16	0.330
Gas existing	0		30	19.50	0.47	0.515
Gas OCGT	400		30	19.50	0.47	0.410
Gas CCGT	680		30	35.10	0.52	0.613
Gas CCS	1330		30	50.45	1.92	0.538
Gas CCS support	1350		30	77.63	1.16	0.480
Oil existing	0		40	19.50	0.00	0.376
Bio existing	0		40	44.33	0.00	0.390
Bio 10% co-firing	1600		40	32.40	0.48	0.470
Bio 10% co-firing CCS	2530		40	50.04	3.28	0.395
Nuclear	2350		60	119.52	1.60	0.365
Wave	4525		25	153.85	0.00	0.665
Geothermal	5500		40	92.31	0.00	0.900
Hydro regulated	3000		60	125.00	0.00	1.000
Hydro run-of-the-river	4000		60	125.00	0.00	1.000
Hydro pumped storage	1250		60	108.00	0.00	1.000
Wind onshore	1150		25	50.85	0.00	1.000
Wind offshore	3480		25	117.17	0.00	1.000
Solar PV	1450		25	22.75*	0.00	1.000
Solar PV (low)	1000		25	22.75*	0.00	1.000
Generic storage	800	80	25	50.00	1.00	0.700
Battery storage	250	350	10	10.50	0.00	0.700
Hydrogen storage	750	1	15	0.00	0.00	0.400

Figure 27: Technology cost and performance assumptions for 2030 (note that fixed O&M costs were varied as a sensitivity study to 19.5 €/kW/a and 16.25 €/kW/a)*

Technology 2050	Investment costs (€/kW)	(€/kWh)	Lifetime (years)	Fixed O&M (€/kW/a)	Variable O&M (€/MWh)	Efficiency (%)
Lignite existing	0		40	32.40	0.48	0.368
Lignite	1600		40	32.40	0.48	0.490
Lignite CCS	2250		40	44.73	3.28	0.430
Lignite CCS support	2600		40	79.65	1.18	0.310
Coal existing	0		40	31.05	0.46	0.391
Coal	1500		40	31.05	0.46	0.490
Coal CCS	2150		40	41.39	2.46	0.430
Coal CCS support	2500		40	78.30	1.16	0.330
Gas existing	0		30	19.50	0.55	0.550
Gas OCGT	400		30	19.50	0.55	0.420
Gas CCGT	800		30	54.00	0.80	0.660
Gas CCS	1250		30	64.73	2.20	0.600
Gas CCS support	1350		30	77.63	1.16	0.480
Oil existing	0		40	19.50	0.00	0.376
Bio existing	0		40	40.30	0.00	0.399
Bio 10% co-firing	1600		40	32.40	0.48	0.490
Bio 10% co-firing CCS	2250		40	44.73	3.28	0.430
Nuclear	1700		60	104.58	1.40	0.370
Wave	3000		25	153.85	0.00	1.000
Geothermal	5500		40	92.31	0.00	1.000
Hydro regulated	3000		60	125.00	0.00	1.000
Hydro run-of-the-river	4000		60	125.00	0.00	1.000
Hydro pumped storage	1250		60	108.00	0.00	1.000
Wind onshore	1100		25	47.30	0.00	1.000
Wind offshore	2880		25	96.36	0.00	1.000
Solar PV	1000		25	26.00*	0.00	1.000
Solar PV (low)	200		25	26.00*	0.00	1.000
Generic storage	600	60	25	50.00	1.00	0.700
Battery storage	200	200	10	6.00	0.00	0.700
Hydrogen storage	500	1	15	0.00	0.00	0.420

Figure 28: Technology cost and performance assumptions for 2050 (note that fixed O&M costs were varied as a sensitivity study to 19.5 €/kW/a and 13 €/kW/a)*

Annex III: Glossary

a	Annum
b/	Billion
BASE	Base power plant with CO_2 capture
BAU	Business-as-usual
BF	Blast Furnace
Bio	Biomass
BOF	Basic Oxygen Furnace
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	CO_2 Capture and Storage
CfD	Contracts for Difference
CFD	Computational Fluid Dynamics
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DRI	Directly Reduce Iron
EAF	Electric Arc Furnace
E-storage	Electricity Storage
ETS	Emissions Trading Scheme
EU	European Union
EUA	Emission Unit Allowance
FCC	Fluid Catalytic Cracker
GCAM	Global Change Assessment Model
kg	Kilogramme
GHG	Greenhouse Gas
GJ	Giga Joule
GT	Gas Turbine
hr	Hour
HRC	Hot Rolled Coil
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
km	Kilometre
kWh	Kilowatt Hour
kW	Kilowatt
LCOE	Levelised Cost of Electricity
M	Million
Mt	Mega (million) Tonnes
MWe	Megawatt (electric)
MWh	Megawatt Hour
NER300	New Entrant Reserve (300)
OCGT	Open Cycle Gas Turbine
OPTI	Optimised power plant with CO_2 capture
O&M	Operation and Maintenance
OBF	Oxy-blast Furnace
ppm	Parts Per Million
PV	Photovoltaic
RES	Renewable Energy Sources
Spec	Specific (emissions per unit produced)
t	Tonne
T&S	CO_2 Transport and Storage
UK	United Kingdom
ULCOS	Ultra-Low CO2 Steelmaking
US	United States
WACC	Weighted Average Cost of Capital
w/o	Without
yr	Year

Annex IV: Members of the ZEP Temporary Working Group Market Economics

Name	Country	Organisation
Bruce Adderley	UK	Sheffield University
Gian Luigi Agostinelli	Switzerland	General Electric
Heinz Bergmann	Germany	IZ Klima
Karl Buttiens	Luxembourg	ArcelorMittal
Umberto Desideri	Italy	University of Pisa
Niall Mac Dowell	UK	Imperial College
Mark Downes	UK	Shell
Paul Fennell	UK	Imperial College
Ward Goldthorpe	UK	Crown Estate
Lily Gray	The Netherlands	Shell
Gianfranco Guidati	Switzerland	General Electric
Jonas Helseth	Belgium	Bellona Europa
Zoe Kapetaki	Belgium	Global CCS Institute
Nicolas Kraus	Belgium	EPPSA
Ian Luciani	UK	BP
Wilfried Maas	The Netherlands	Shell
Kjetil Midthun	Norway	SINTEF
Theo Mitchell	UK	CCSA
Hans Modder	The Netherlands	ZEP Secretariat
Magnus Moertberg	Germany	General Electric
Tim Peeters	The Netherlands	Tata Steel
Peter Radgen	Switzerland	Swiss Federal Office of Energy (SFOE)
Alan Reid	Belgium	CONCAWE
Christian Skar	Norway	Norwegian University of Science and Technology (NTNU)
Charles Soothill	Switzerland	General Electric
Katrin Stoetzl	Belgium	EUTurbines
Kazimierz Szynol	Poland	PKE S.A.
Asgeir Tomasgard	Norway	SINTEF
Robert van der Lande	The Netherlands	ZEP Secretariat
Rob van der Meer	The Netherlands	HeidelbergCement
Ralf Wezel	Belgium	EUTurbines
Keith Whiriskey	Belgium	Bellona Europa

Zero emissions platform

November 2015

European Technology Platform for Zero Emission Fossil Fuel Power Plants