Chapter 7
Economic Analysis of Carbon Capture in the Energy Sector

Wilhelm Kuckshinrichs and Stefan Vögele

Abstract The cost of carbon capture is a crucial factor for the deployment of the technologies in the electricity sector. In general, much higher electricity generation costs arise in case of carbon capture. With an increase of approximately 80 %, lignite-based CCS plants are particularly affected. The CO_2 avoidance costs are € 34–38/tCO_2 for lignite plants, € 41–48/tCO_2 for hard coal plants, and with approx. € 67/tCO_2 highest for natural gas plants. This depends on the lower level of CO_2 avoided in case of gas-fired power plants. Only when the price of allowances rises to these levels will the use of CCS power plants be cost-effective.

However, capture plants must be refinanced through the electricity market, as long as other market design options, e.g. capacity market or feed-in-tariffs, don't render possible returns. In general, the question arises as to the degree to which higher revenues due to merit order effects can cover the additional investment costs for capture plants and the subsequent transport and storage of CO_2. With further increase of renewable energy, there is a danger that the power plant capacities of an existing fleet will be potentially underused. As a result, there would be a short-term cost recovery problem for fossil power plants. Regardless of the possible development of capacity markets, the comparatively high refinancing needs compared to conventional power plants will remain if capacity revenues are to be incorporated.

Keywords Levelized cost of electricity • CO_2 avoidance cost • Merit order effect • Capacity market

7.1 Introduction and Motivation

This chapter concentrates on the economic analysis of the use of CCS in the electricity industry. The focus is on cost projections for carbon capture technologies, because the costs for CCS arise mainly from the capture of CO_2 and only to a lesser extent from its transportation and storage. For economic considerations, the

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W. Kuckshinrichs (✉) • S. Vögele
Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), Forschungszentrum Jülich GmbH, D-52425 Jülich, Germany
e-mail: w.kuckshinrichs@fz-juelich.de; s.voegele@fz-juelich.de

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price of CO_2 plays a key role because it alters the relative costs of the individual technologies depending on the technical specifications, and this is the only way of economically assessing the use of CCS technologies. In addition to investment costs and efficiency, the number of full-load hours is another relevant parameter.

Carbon capture technologies have not yet reached a level of maturity that can satisfy the requirements of commercial use in the electricity industry. Refining the technologies, building demonstration plants, and constructing commercial plants are tasks associated with a series of uncertainties of a technical and scientific nature, such as integration in the power plant process, level of investment costs, and economies of scale. Consequently, no empirical cost data are available for commercial usage yet. A series of investigations deals with expert estimates on the costs of technologies for demonstration plants and for the first commercial power plants. Within the framework of commercialization, the potential to cut the investment costs in particular is discussed using learning curves.

In the current electricity market design (energy only), a merit order or supply function covering the variable costs of power plants is relevant for pricing on the wholesale market. Here, it is of central significance whether and how CCS power plants contribute to the pricing process on the wholesale market, and what implications this could have for the refinancing of investments in CCS power plants.

This chapter is structured on the basis of the approach described. Following the introduction, Sect. 7.2 will discuss the process and cost parameters, as well as learning curve projections. Section 7.3 will examine the costs of electricity generation and CO_2 avoidance, and present cost projections for Germany. Using sensitivity calculations, key parameters such as the CO_2 price and number of full-load hours will be analysed in terms of their economic significance. Against the background of the discussion on the future structure of electricity supply, Sect. 7.4 will classify CCS technologies from an energy economics point of view within the framework of the electricity market design. Section 7.5 will conclude with a summary.

7.2 Demonstration Plants

7.2.1 Demonstration Plants for Electricity Generation

Against the background of EU efforts aiming at the demonstration of CCS technologies, an information system for energy technologies (SETIS[1]) was created as part of the SET-Plan Initiative.[2] In a study, Tzimas (Tzimas 2009) analysed and harmonized cost data from 13 different sources (Table 7.1). These sources comprise

[1] SETIS: SET-Plan Information System.

[2] SET-Plan: European Strategic Energy Technology Plan.

Table 7.1 Reference values for process and cost parameters for CCS demonstration power plants (~2,015)

Fluctuation margins for cost data according to Tzimas ±30 %.		Reference plants		CCS demonstration plants			
		PF	NGCC	IGCC-CCS	PF-CCS	Oxyfuel	NGCC-CCS
Specifications							
Net capacity	MW_e	400	400	400	400	400	400
Efficiency	%	46	58	35	35	35	46
Carbon capture efficiency	%	–	–	85	85	85	85
Cost data							
Investment	$€_{2011}$/kW	1,546	776	2,833	2,614	3,032	1,359
FOM	$€_{2011}$/kW	67	28	78	68	94	40
VOM	$€_{2011}$/MWh	0.9	0.05	2.2	4.7	0.9	0.9

Source: Adapted from Tzimas (2009)
FOM fixed operating and maintenance costs, *VOM* variable operating and maintenance costs, *PF* pulverized fuel, *NGCC* natural gas combined cycle, *IGCC* integrated gasification combined cycle. Availability: 85 %. Cost data are extrapolated using 1.5 %/year from $€_{2008}$ to $€_{2011}$

pre-feasibility studies, cost models, literature reviews, and expert opinions from industry and other organizations, and thus provide cost projections for CCS plants in different ways and with varying degrees of detail. Tzimas identifies pre-feasibility studies for concrete plant planning as the sources with the highest degree of data robustness.

With respect to technical and economic parameters, a difference must be made between demonstration projects and the commercial use of CCS power plants. Demonstration projects prove that a plant can be used on an industrial scale, and they explicitly aim to acquire experience on the application of the technology and to induce the first learning effects. Other learning effects will arise during the commercial operation of plants.

For coal-fired power plants, no significant difference in the investment costs could be identified for the various technology lines, even though the absolute difference of the values presented was $€_{2008}$ 400/kW. Assuming a determined reference value $€_{2011}$ 2,823/kW, the deviation is only ±7 %. Based on a data inaccuracy of approx. 30 % (Tzimas 2009), this is a relatively low value.

Little information is available on the fixed (FOM) and variable (VOM) operating and maintenance costs. Nonetheless, the literature data for IGCC, PF, NGCC plants with CCS are in good agreement with each other. The costs for transportation and storage are project-specific and depend on the location of the conversion plant, the storage facility, the pipeline routes, and the type of storage formation. They vary between $€_{2011}$ 5/t and $€_{2011}$ 42/t. The average cost of transportation and storage is around $€_{2008}$ 20/tCO_2. Cost projections by IPPC (2005) and MIT (2007), in contrast, are much lower. On average, investment costs of around €$_{2011}$ 1,900/kW$_e$ are incurred for CCS plants (cf. overview in Lohwasser and Madlener 2009). The low costs must be interpreted against the background of the originally more optimistic cost estimates.

7.2.2 Learning Rates

An empirical analysis shows that the specific capital investment for energy conversion plants decreases at a considerable rate with the total installed capacity over long periods of time (Rubin et al. 2004; McDonald and Schrattenholzer 2001). Compared to technologies such as wind energy or photovoltaics there are relatively few publications on learning curves for fossil-fired power plants with carbon capture. In analogy to technology developments such as those for the desulfurization and denitrification of power plants, some empirical values are also taken into account. Experience has shown that learning rates of 10–12 % are also expected for plants with carbon capture. Considerably higher rates are quoted only for photovoltaics (approx. 20 %) and much lower, partially negative, rates are quoted for nuclear energy (Al-Juaied and Whitmore 2009).

A detailed overview in Van den Broek et al. (2009) distinguishes learning rates for capture technologies (without transportation and storage) according to the plant components and parameters such as efficiency and availability. For plant components, the mean learning rates range between 0 % for CO_2 compression to 11 % for carbon capture using amine scrubbing and 12 % for Selexol concepts in IGCC plants. The mean learning rates cover a range with upward and downward deviations of 50 %.

In Neij (2008), learning rates of 5 % are assumed for all types of coal-fired power plants including CCS technologies. For gas-fired plants, a learning rate of 10 % is assumed. Furthermore, it is suggested that sensitivities of ±2 % be calculated in order to account for uncertainties. A more pessimistic assessment is provided by the GCCS Institute (Global CCS Institute 2011) with a predicted cost reduction of less than 5 % for the transition from FOAK (first of a kind) to NOAK (n^{th} of a kind), which is explained by the fact that a series of key components for carbon capture are already tried-and-tested technologies, and the level of maturity will therefore only increase minimally with increasing capacity, which means that no significant potential cost reduction is expected. However, greater potential for reducing costs is expected after the introduction of the next generation of technologies (Rubin et al. 2007a).

Rubin et al. (2007b) derive learning rates of 2.1 % (PC), 5.0 % (IGCC), 2.8 % (oxyfuel), and 2.2 % (NGCC) for investment costs. Expanding capacity to 100 GW (which is equivalent to doubling the capacities around 3.5–4.5 times) results in percentage reductions in the investment costs totalling 15 % (PC + IGCC), 13 % (oxyfuel), and 20 % (NGCC). For operating and maintenance costs, the corresponding learning rates are 5.7 %, 4.8 %, 3.5 %, and 3.9 %, respectively.

Preliminary Conclusions

- The degree of uncertainty with regard to costs is high for demonstration power plants.
- For demonstration plants, the following reference values are proposed for investment costs (calculated from Tzimas 2009):
  - IGCC-CCS: €$_{2011}$ 2,833/kW
  - PF-CCS: €$_{2011}$ 2,614/kW
  - Oxyfuel: €$_{2011}$ 3,032/kW
  - NGCC-CCS: €$_{2011}$ 1,359/kW
- The cost uncertainty is estimated as ± 30 %. In relation to a mean value of €$_{2011}$ 2,823/kW, coal-based technology lines therefore show no significant differences in investment costs.
- For carbon capture, there is only very little experience and knowledge on learning curves. Initial analyses quote learning rates of 2.1 % (PC), 5.0 % (IGCC), 2.8 % (oxyfuel), and 2.2 % (NGCC) (Rubin et al. 2007b).

7.3 Commercial Use of CCS

7.3.1 Cost and Process Parameters

Over the past few years, a series of cost analyses have been published on power plants with carbon capture (e.g. ETP ZEP 2011; Global CCS Institute 2011; IEA NEA OECD 2010; IPCC 2005; McKinsey 2008; MIT 2007). In the context of an increasing number of pilot and demonstration projects, knowledge of technical processes is improving, and higher costs are now being assumed, particularly for investments. However, there are still numerous uncertainty factors, which must be taken into account for cost and process parameters. Expectations are therefore often still very different.

The results of individual cost analyses cannot be compared directly due to the different assumptions regarding reference year, plant sizes and configurations, fuel prices, interest rates, etc. (Rubin 2012). The most recent ZEP study (ETP ZEP 2011) compares the results using harmonized reference parameters. Figure 7.1 shows the results for hard coal plants with carbon capture as an example.

For post-combustion plants, no clear trend can be discerned for the costs of generating electricity. Costs range between € 65/MWh to much more than € 80/MWh. For IGCC pre-combustion and oxyfuel power plants, the costs of generating electricity are similarly high, ranging from € 60/MWh to almost € 80/MWh.

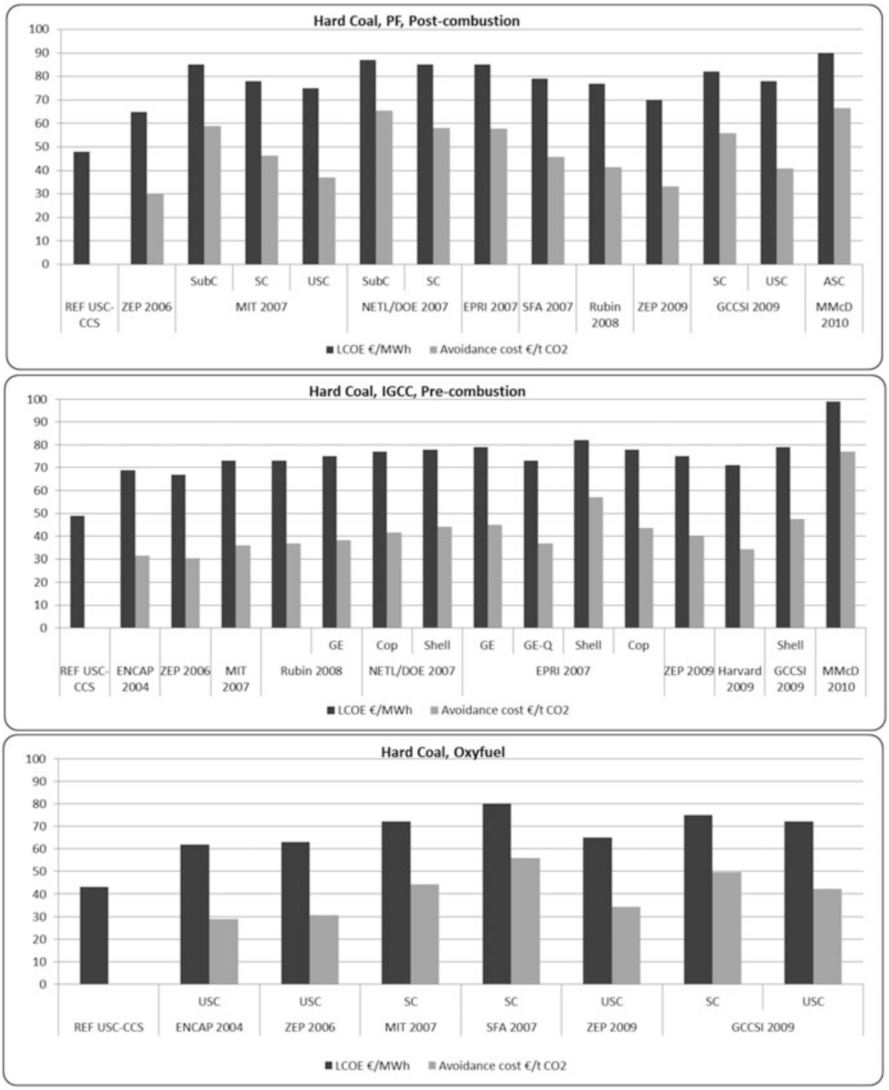

Fig. 7.1 Electricity generation and CO_2 avoidance costs for hard coal plants with carbon capture from different studies
Fuel price: € 2.42/GJ
For IGCCs, the power plant concepts of the companies are depicted
The following studies were incorporated: (Al-Juaied and Whitmore 2009; ENCAP 2008, 2009; Global CCS Institute 2009; Holt and Booras 2007; McKinsey 2008; MIT 2007; MMcD 2010; NETL 2007; Rubin et al. 2007a; SFA Pacific Inc. 2007; ZEP 2008)
(Source: Adapted from ETP ZEP 2011)

The CO_2 avoidance costs in post-combustion plants have a large range from € 30/tCO_2 to approx. € 65/tCO_2. For IGCC pre-combustion and oxyfuel plants, this range is smaller but still appreciable at approx. € 30–55/tCO_2. These figures reveal no clear advantage for any of the technologies discussed. The cost values for lignite plants are lower, and for natural gas plants, they are higher, as expected.

Tzimas and Georgakaki[3] (2010) and ETP ZEP (2011) compared the demonstration plants (Table 7.1) with the first commercial plants in 2020 and revealed a clear increase in the expected investment costs. This increase for PF-CCS and IGCC-CCS is particularly high for lignite and not quite as high for hard coal. ETP ZEP is much more optimistic with its expectations for oxyfuel plants: the expected specific investment costs decrease. For natural gas plants, in contrast, an increase is expected in the specific investment costs.

Compared to earlier analyses for commercial application in Germany (Hake et al. 2009), considerable changes emerge for individual cost components. The specific investment costs tend to be much higher both for the respective reference plants as well as for plants with carbon capture: for lignite plants between 50 and 75 %, for hard coal plants between 40 and 55 %, and for natural gas between 60 and 100 %. A notable exception here is oxyfuel technology, for which the specific investment costs for hard coal are estimated as 25 % higher and for lignite merely 9 % higher than in Hake et al. (2009). Fixed operating costs with the exception of the natural gas reference plant are consistently higher, while estimates for variable operating costs – again with the exception of the natural gas reference plant – tend to be much lower. Overall, a clear transition in the cost structure towards fixed costs is visible (see Lohwasser and Madlener 2009). The capital cost share increases considerably, and the share of fixed operating costs also increases. This is accompanied by a loss of economic flexibility of the plants, which are reliant on high annual utilization because of the high share of fixed costs. In a future energy supply system with a high proportion of fluctuating renewable energy and increasing demands on the flexible use of fossil-fired power plants, this situation is not very beneficial.

Table 7.2 shows important process and cost parameters based on Hake et al. (2009) and ETP ZEP (2011), which are assumed for power plant concepts in Germany and provide the basis for the subsequent calculations.

The investment costs of lignite power plants tend to be higher than those of hard coal power plants. For natural gas plants, the investment costs are much lower but the fuel costs are much higher. Compared to the respective reference plants, the investment costs of power plants with carbon capture are approx. 70–90 % higher.

[3] The cost breakdown in Tzimas & Georgakaki reflects the situation up to 2007 (Tzimas and Georgakaki 2010).

Table 7.2 Process and cost parameters for the first commercial CCS power plants

		Lignite				Hard coal				Natural gas	
		REF	PF-CCS	IGCC-CCS	Oxyfuel	REF	PF-CCS	IGCC-CCS	Oxyfuel	REF NGCC	NGCC-CCS
Specifications											
Capacity	MW_{el}	1,100	1,100	900	900	1,100	1,100	900	900	400	400
Lifetime	a	40	40	40	40	40	40	40	40	25	25
Efficiency	%	46.5	34.9	39.8	38.5	49.5	37.8	41.8	41.5	61.0	52.5
Carbon capture efficiency	%	–	90	90	90	–	90	90	90	–	90
Cost data											
Investment	$€_{2011}$/kW	1,700	2,950	3,200	2,900	1,600	2,800	3,100	2,800	700	1,250
Fixed costs	$€_{2011}$/kW	29	58	70	58	28	54	66	54	19	37
Variable costs	$€_{2011}$/MWh	3	5	5	5	3	5	5	5	1	3

Source: Calculation based on Hake et al. (2009) and ETP ZEP (2011)

7.3.2 Electricity Generation and CO_2 Avoidance Costs

In order to predict the costs of CCS technologies, the electricity generation costs [€/MWh] must be taken into account for production as must the CO_2 avoidance costs [€/tCO_2] for the reduction of CO_2 emissions.

Electricity generation costs reflect the costs of converting primary energy carriers and/or fuels into electricity along the process chain of a power plant. The costs of capturing CO_2 increase the total plant costs in three ways: (1) costs for additional plant components, e.g. CO_2 compression; (2) costs for additional plant capacity required to compensate for efficiency losses if net capacity is to be kept at the same level; (3) costs for additional fuel due to efficiency losses. In the system, additional costs are also incurred for the transportation and storage of CO_2.

In contrast, the CO_2 avoidance costs reflect the costs incurred for the CO_2 emissions that are not released into the atmosphere and are thus 'avoided'. The avoidance costs are calculated by comparing a reference technology without CCS with the corresponding technology with CCS. The CO_2 avoidance costs must be distinguished from the carbon capture costs. These are based on the corresponding amount of CO_2 captured at the power plant. The CO_2 avoidance costs are always higher than the carbon capture costs due to efficiency losses and the necessary compensation by means of a higher output and a higher fuel input.

For the following economic analysis, the concept of the levelized cost of electricity (LCOE) is used. This approach makes a financial analysis possible that focuses on estimating the electricity generation costs by taking into account the most important cost components, such as capital costs, fuel costs, and operating costs. The approach calculates the cash value of investments and the operation of a plant over the lifetime of the plant converted into uniform periodic payments.[4] The electricity generation costs can be calculated in this way for plants with and without carbon capture.

In addition to the process and cost parameters of power plants (Table 7.2), a number of other parameters also play a key role for the economic analysis. Of particular interest are the investment costs and the efficiency of the plants, as well as the transportation and storage costs. Berry (2008) also refers to the fuel costs, which have been taken into account in the approach here with price escalation (Table 7.3). For further analyses, the fundamental data for the energy sector shown in Table 7.3 are included in the calculations.

Fuel prices increase in real terms by approx. 1.2 %/a in accordance with Lindenberger et al. (2010). Transportation and storage costs vary widely depending on the transport distance, the amount transported, spatial conditions for a pipeline route, etc. In the literature, the costs quoted vary depending on the pipeline length, the terrain, and the gas volume, as well as on the storage medium (e.g. onshore/offshore, depleted gas field/saline aquifer) (Tzimas 2009). They range between € 5/tCO_2 (Global CCS Institute 2011) and € 9–18/tCO_2 (McKinsey 2008).

[4] For the mathematical principles, see Appendix.

Table 7.3 Economic data for the energy sector

Fuel price	$€_{2011}/GJ$	
Lignite		1.52
Hard coal		2.63[a]
Natural gas		6.39[a]
Transportation and storage costs	$€_{2011}/tCO_2$	5.00
Escalation	%/a	
Fuel price		1.20[a]
Operating costs		1.50
Transportation and storage costs		1.50
Full-load hours	h/a	7,500
Interest rate	%	5.00

[a]Calculated based on Lindenberger et al. (2010)

The infrastructural aspect is also important because a future transport network depends on the geographical distribution of the storage facilities and the CO_2 sources. For the following analysis, simplified transportation and storage costs of € 5/tCO_2 are assumed.[5] The plants are assumed to operate with a high number of full-load hours.

The electricity generation costs at high utilization are shown in Fig. 7.2. A clear increase is visible for the electricity generation costs (LCOE) of CCS plants compared to the reference plants: for lignite from € 36/MWh to up to € 65/MWh (IGCC-CCS), for hard coal from € 44/MWh to up to approx. € 73/MWh (IGCC-CCS), and for natural gas from € 54/MWh to € 73/MWh (CCGT-CCS).

The CO_2 avoidance costs at high utilization are lowest for lignite plants at € 34–38/tCO_2 and highest for natural gas plants at € 67/tCO_2. Of the coal-fired power plants, the oxyfuel CCS plant is the most advantageous (Fig. 7.3).

7.3.3 *Sensitivity Calculations*

Against the background of uncertainties regarding the process and cost parameters as well as the economic data for the energy sector, sensitivities are calculated in the following in order to portray the impacts on the electricity generation costs of CCS technologies. The focus here is on monetary parameters (investment, fuel, CO_2 allowances) and process parameters (efficiency, full-load hours).

The investment costs represent the highest share of fixed costs. Higher investment costs cause a direct increase in the generation costs.

In order to account for different development opportunities on the electricity market, the number of full-load hours is modified in the following. The number of full-load hours is significant for offsetting other fixed costs and the investment

[5] For a differentiated analysis of transportation and infrastructure costs, see Chap. 9.

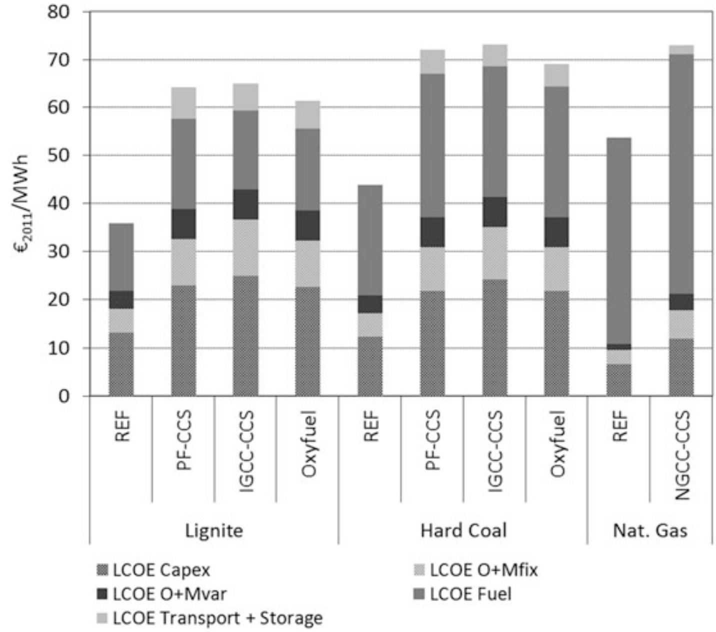

Fig. 7.2 LCOE based on fundamental economic data for the energy sector (With no learning rate effect)

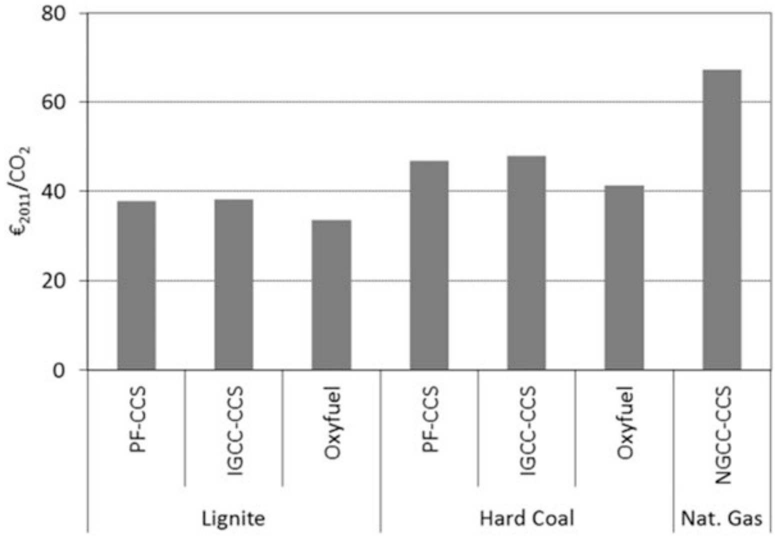

Fig. 7.3 CO_2 avoidance costs based on fundamental economic data for the energy sector (With no learning rate effect)

costs. The number of full-load hours has an impact on the apportionment of the fixed costs so that a higher number of full-load hours facilitate a degression of the generation costs.

The prices of fuel and emissions allowances, on the other hand, affect the variable costs, so that if they are increased, the variable costs also increase.

Changes in efficiency, in contrast, affect both the fixed and variable costs. A higher efficiency allows more electricity to be generated, and thus improves the apportionment of fixed costs. At the same time, improved efficiency leads to improved fuel utilization, which is accompanied by decreasing CO_2 intensity, and thus a lower specific need for CO_2 allowances. The variable costs therefore decrease.

The trading of allowances is a market-based solution for pricing CO_2. In IEA NEA OECD (2010), the price of CO_2 is explicitly incorporated as a variable cost factor in calculating the LCOE. This increases by a value that is calculated based on the price of allowances [€/tCO_2] multiplied by the CO_2 intensity [tCO_2/MWh]. The degree to which these technologies are affected by the level of the CO_2 price depends on their CO_2 intensity. In general, the higher the CO_2 intensity (after capture for CCS), the more the CO_2 price affects the generation costs.

For coal-fired power plants without CCS, this aspect is particularly relevant. The high CO_2 emissions must be covered by CO_2 allowances, while CCS plants only require allowances to cover the remaining CO_2 emissions. However in this case, the lower allowance costs must be balanced against the much higher investment costs. Ultimately, this alters the relative competitiveness of the conversion technologies (Nicholson et al. 2011). Only above a certain emissions allowance price level can the use of CCS power plants be justified. Conversely, it may be cost-effective for (permanently) low allowance prices to operate power plants without carbon capture.

Figure 7.4 shows the results of sensitivity calculations for CCS power plants. The calculations are based on a $\pm$10 % variation in the starting value of the parameters (Table 7.2 and Table 7.3). The base CO_2 price is assumed to be € 30/tCO_2.

The reaction patterns are very similar for all coal technologies. Variations of $\pm$10 % in full-load hours, efficiency, and fuel and purchase prices lead to changes in the generation costs of approx. € 2–4/MWh. These parameters are extremely important for the technologies discussed here, although sometimes in a different sequence. For lignite, the number of full-load hours tends to be pivotal, while for hard coal, efficiency tends to be more important. In both cases, the purchase price is not of overriding importance.

A very low number of full-load hours (~2,500 h) tends to cause the CO_2 avoidance costs to double. These costs then tend to be highest for natural gas plants (€ 123/tCO_2), and lowest for lignite plants (€ 71–78/tCO_2). For a low number of full-load hours, the avoidance costs for hard coal plants are very high at € 86–107/tCO_2. Overall, it appears that a relatively high CO_2 price is necessary to justify the implementation of the CCS technologies described here, particularly for a low number of full-load hours.

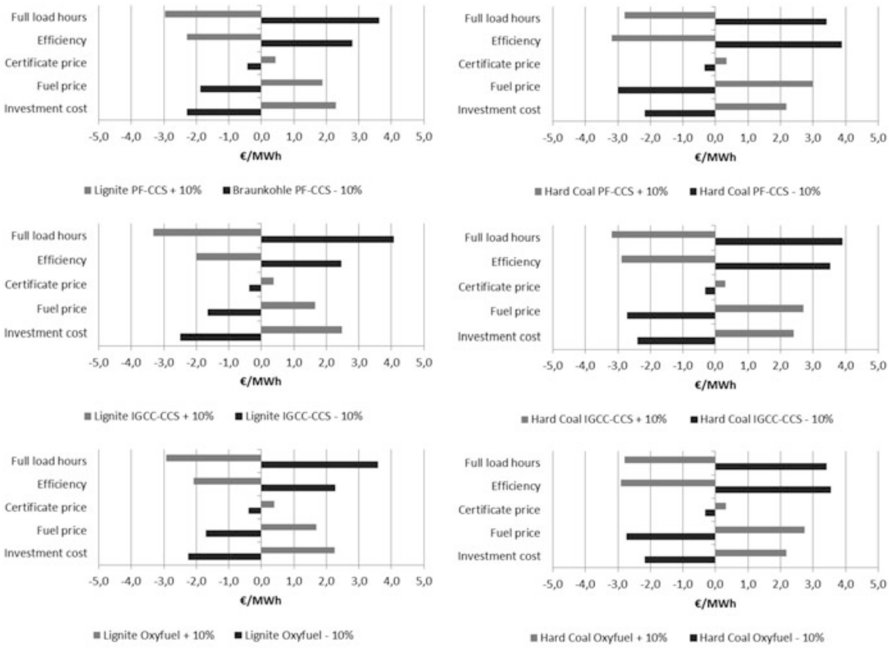

Fig. 7.4 Sensitivity of electricity generation costs for parameter variation. Parameters modified by ± 10 % respectively; € 30/tCO_2 is assumed for CO_2 allowances

Variations in the CO_2 price play a comparatively small role. A variation of ±10 % in the initial price of € 30/tCO_2 results in a change in the generation costs of approx. € 0.5/MWh.

Preliminary Conclusions

- The costs of capturing CO_2 increase the plant costs in three ways: (1) costs for additional plant components, e.g. CO_2 compression; (2) costs for additional plant capacity to compensate for efficiency losses if net capacity is to be kept at the same level; (3) costs for additional fuel due to efficiency losses.
- In the system, additional costs are also incurred for the transportation and storage of CO_2. They range between € 5/tCO_2 (Global CCS Institute 2011) and € 9–18/ tCO_2 (McKinsey 2008). Depending on technical parameters the costs may be even higher in special cases.
- For the first commercial plants, considerably higher investment costs are expected than in earlier studies. Investment costs for CCS power plants tend to be around 70–90 % higher than for conventional power plants without CCS.
- The electricity generation costs for CCS power plants at a high utilization are approx. 26 % (natural gas) to 80 % (lignite) higher than the reference plants. The

CO_2 avoidance costs are € 34–38/tCO_2 for lignite power plants, approx. € 41–48/tCO_2 for hard coal plants, and approx. € 67/tCO_2 for natural gas plants.
- The utilization of lignite CCS power plants is only cost-effective if the price of allowances is at least approx. € 34–38/tCO_2. Cost effectiveness demands higher emissions allowance prices for hard coal, and considerably higher allowance prices for natural gas.
- Variations of ± 10 % in full-load hours, efficiency, and fuel and purchase prices lead to changes in the generation costs of approx. € 2–4/MWh. A corresponding variation of the CO_2 price, on the other hand, is not significant.
- A very low number of full-load hours (~2,500 h) tends to cause the CO_2 avoidance costs to double. As a result, a relatively high CO_2 price would be necessary to justify the implementation of the CCS technologies described here.

7.4 Electricity Production and Power Exchange Price for CCS Power Plant Usage in Germany

While the last section focused on the technical costs, this section will concentrate on the issue of whether and how the use of CCS power plants can influence the pricing process on the electricity wholesale market as well as producer surplus. Producer surplus is calculated for the electricity sold from the difference between the price of electricity and the variable power plant costs. Producer surplus allows the electricity suppliers to refinance their power plant investments. C.p. the price level of CO_2 allowances plays an important role here.

7.4.1 Pricing on the Electricity Market

The merit order is significant for pricing on the electricity market. It is a supply function, and ranks the power plant capacities in order of merit based on their variable costs. Power plants with low variable costs (e.g. wind energy, photovoltaics, and lignite power plants) are utilized first, followed by power plants with the next-highest variable costs (e.g. hard coal power plants, then gas power plants).[6]

The variable costs of fossil-fired power plants are influenced by CO_2 emissions allowance trading. The decisive factors here are the price of allowances (€/tCO_2), which is set on the electricity market, and the specific CO_2 emissions (tCO_2/MWh) of each individual power plant. Low CO_2 prices mean that the use of conventional power plants without CCS is more advantageous than the use of CCS power plants despite relatively high specific CO_2 emissions if the fuel costs of CCS power plants are correspondingly high. This depends on the efficiency losses of the CCS power

[6] The prioritization of feed-in from renewables is anchored in the legislation.

plant. This situation can change for higher allowance prices, which would then make CCS power plants relatively more advantageous in relation to variable costs, and the merit order would then alter accordingly. A quantity effect can also emerge as an additional effect if the electricity export also changes as a result of the price effects. Taking account of the electricity price and production volume, altered producer surpluses could result as a consequence.

7.4.2 Use of CCS Power Plants

For the analysis, different scenarios were created for different CO_2 allowance prices and for additional conventional and/or renewable energy capacity. An overview is shown in Table 7.4.

The model calculations were specified based on studies by EURELECTRIC and ENTSO-E on the development of future electricity generation in Europe (EURELECTRIC 2010; ENTSO-E 2011a, b). Data on installed power plant capacity in 2030 were taken from the EURELECTRIC study. The study was also used to derive specific annual efficiencies for the selected power plant types. Furthermore,

Table 7.4 Scenario overview for merit order analysis

Name of scenario	Description
Reference scenario	Situation in 2030
REF20	CO_2 allowance price of € 20/tCO_2
REF30	CO_2 allowance price of € 30/tCO_2
REF40	CO_2 allowance price of € 40/tCO_2
REF30 + RE	REF30 scenario with increased renewable energy capacity (+10 GW wind, +20 GW PV, +10 GW gas as backup)
REF30red + RE	REF30 scenario with reduced coal-fired power plant capacity (−10 GW) and increased renewable energy capacity (+10 GW wind, +20 GW PV, +10 GW gas as backup)
CCS scenarios	In contrast to the reference situations, 14.6 GW hard coal power plants and 13.7 GW lignite power plants in Germany are equipped with CCS
CCS20	CO_2 allowance price of € 20/tCO_2
CCS30	CO_2 allowance price of € 30/tCO_2
CCS40	CO_2 allowance price of € 40/tCO_2
RE-CCS scenarios	
CCS30 + RE	CCS30 scenario with an additional 10 GW wind and 20 GW PV (+10 GW gas as backup)
CCSred30 + RE	CCS30 scenario with reduced CCS capacity (instead of 28 GW only 18 GW) but with an additional 10 GW wind and 20 GW PV (10 GW gas as backup)

data on the development of the demand for electricity were taken from the study. As the average end-use price for electricity is considerably higher than the prices on the electricity market, and thus (at least in the short term) no reaction is expected from the end users to compensate for the price changes on the spot market, an inelastic electricity demand was assumed.

The data on existing and expected future power exchange capacities in Europe were taken mainly from ENTSO-E (2010, 2012). Data on the specific operating costs of power plants were taken from the IEA Outlook (2011), and calculated on the basis of data on the power-plant-specific efficiencies and fuel prices (IEA 2011).

In the reference scenarios, the situation is described without CCS for different allowance prices. The reference scenarios were compared to scenarios which assume the use of CCS in Germany. Here, it was assumed that 14.6 GW hard coal power plants and 13.7 GW lignite plants are operated with CCS. Of these, 19 GW are old power plants retrofitted with CCS.

In order to analyse the effects of the availability or non-availability of renewables, the calculations were performed on an hourly basis, i.e. for every hour in a year, the optimal usage of the power plants in the individual countries in Europe was calculated. The calculations are based on a model of power plant use described in Rübbelke and Vögele (2012).

In the scenarios investigated, the use of CCS led to a decrease in the average annual prices on the electricity market. This can be explained by the fact that the use of CCS means that the specially equipped coal-fired power plants are less affected by the price of CO_2 allowances, and thus maintain a competitive edge over conventional coal-fired power plants. An example of the development of electricity prices on the electricity market is shown in Fig. 7.5.

This graph shows the annual distribution of the calculated price of electricity in the scenarios REF30 and CCS30. At 4,400 h, the electricity price in scenario CCS30 is below that of scenario REF30 due to differences in the operating costs

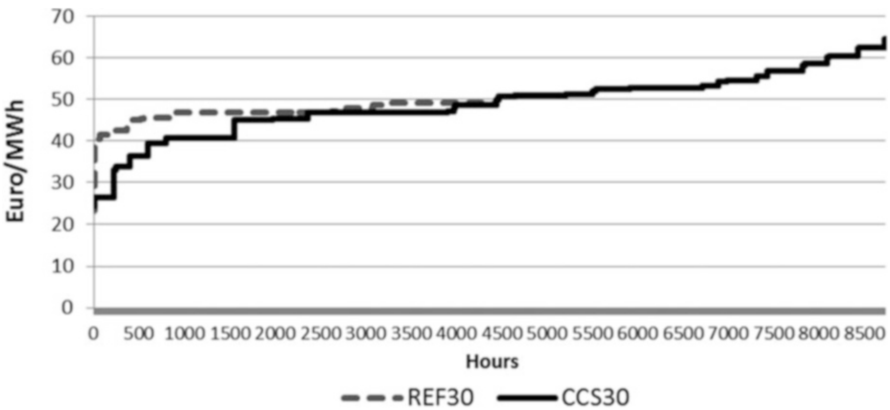

Fig. 7.5 Distribution of electricity prices over a year according to price level

Table 7.5 Impacts of CCS usage on electricity price and production for different CO_2 prices

		CCS20 – REF20	CCS30 – REF30	CCS40 – REF40
Changes in prices (Germany)		−2.2 %	−3.7 %	−6.4 %
Changes in electricity generation (Germany)		+0.9 %	+1.8 %	+4.7 %
Specific contribution margin (Germany)		€ 32/kW	€ 66/kW	€ 89/kW
Amortization period for additional investments	Post-combustion	14–38	7–18	5–13
	Pre-combustion	19–47	9–22	7–16
	Oxyfuel	22–38	10–18	8–13

Note: Estimation of the required years based on IEA (2011), Hake et al. (2009) and ETP ZEP (2011)

of CCS and conventional coal-fired power plants. At these points in time, the electricity price is determined by coal-fired power plants. At other points in time, gas power plants usually determine power plant marginal costs.

Due to changes in operating costs, electricity imports into Germany decrease in the model calculations and domestic production increases. The changes in production coupled with the price changes and the shape of the merit order curve lead to an additional producer surplus. From the additional revenues, specific contribution margins of € 32 per kW installed CCS capacity (comparison of CCS20 with REF20), € 66 (comparison of CCS30 with REF30), and € 89 (comparison of CCS40 with REF40) are obtained.

At a contribution margin of € 32, it takes approx. 14 years of operation to amortize additional investments for post-combustion plants under favourable conditions and about 38 years under unfavourable conditions (i.e. in the case of higher investment costs). In the case of higher investment costs for pre-combustion and oxyfuel plants, the amortization period increases. For higher allowance prices, the refinancing period decreases accordingly (Table 7.5).

Table 7.6 shows the results of a comparison of CCS scenarios with an increased renewable energy capacity. In the scenarios in which the share of renewables has been expanded further than in the reference case, the average annual price of electricity on the spot market is lower than without increased capacity. If the end-users pay the additional investment costs for renewables, as has been the case to date, and the additional revenues generated are then available to cover the additional investment costs for CCS, the specific contribution margins for CCS are € 44/kW (comparison of CCS30 + RE with REF30 + RE) and € 80/kW (comparison of CCS30 + RE with REF30). The use of CCS in the scenarios with an increased renewable energy capacity and unchanged output in the coal area leads to a clear reduction in the prices on the spot market and to an increase in domestic production. A reduction in the use of coal-fired power plants and a simultaneous increase in renewable energy capacity, basically leads to higher average electricity prices because in this case the comparatively more expensive backup capacities must be

Table 7.6 Impacts of CCS usage on electricity price and production for different CO_2 prices and increased renewable energy capacity

	CCS30 + RE		CCSred30 + RE	
Comparative scenario	REF30	REF30 + RE	REF30	REF30red + RE
Changes in prices (Germany)	−9.4 %	−5.5 %	1.2 %	−2.3 %
Changes in electricity generation (Germany)	5.6 %	2.7 %	−3.8 %	0.7 %
Changes in revenues (Germany)	+ € 2.3 billion	+ € 1.3 billion	+ € 2.4 billion	+ € 1.4 billion

used in order to compensate for fluctuations in electricity generation. In the case investigated, the higher costs give rise to a growth in electricity imports. The use of CCS dampens the rising energy carrier prices and the growing electricity imports. As a result, the electricity prices in scenario CCSred30 + RE are lower than those in scenario REF30red + RE. At the same time, domestic production increases in this CCS scenario.

If renewable energy is further integrated into the current electricity market design (‘energy only’), there is a danger that the power plant capacities of an existing fleet will be potentially underused. In addition to the generation cost effect caused by a low number of full-load hours, the drop in residual demand would lead to a merit order effect. As a result, there would be a short-term cost recovery problem for fossil plants in the installed power plant fleet.

The long-term effect involves a decreased investment incentive for new builds. This applies even more so to CCS plants with comparatively high investment costs. Capacity markets attempt to provide a framework for paying compensation for making capacities available. The capital costs of power plants would therefore no longer be exclusively covered by revenues from the energy actually generated, but rather from the revenues of providing capacity as well. In addition, steady capital returns would also be made available for periods during which the power plant produces no electricity (Brunekreeft et al. 2011).

For Germany and Europe, the introduction of capacity markets is a topic of heated debate (Achner et al. 2011; Böckers et al. 2012; Bode and Groscurth 2011; Brunekreeft and Meyer 2011; Cramton and Ockenfels 2012; EWI 2012; Siegmeier and von Hirschhausen 2011). Regardless of the possible concrete development of capacity markets, the comparatively high refinancing needs compared to conventional power plants will remain if capacity revenues are to be incorporated. Against the background of the cost structure of CCS power plants, lignite CCS plants will tend to be used for base load, as shown by analyses within the framework of the discussion of possible capacity markets (EWI 2012). Security of supply will be ensured by gas turbines as backup power plants. The very few full-load hours tend to make the amortization of investment costs in these cases difficult, which mean that revenues from a possible capacity market are more important here.

Preliminary Conclusions

- Low loading because of low prices for CO_2 allowances mean that the operating costs of CCS power plants (despite efficiency losses) are below those of comparable coal-fired power plants. The use of CCS power plants therefore leads to a situation where periods of low electricity demand or periods when wind and photovoltaic plants can only be used to a limited extent give rise to lower electricity prices than in the reference situation. In addition, a merit order effect emerges, i.e. additional revenues are generated.
- Considering the existing uncertainties with regard to the additional investment costs for CCS plants, it can be assumed that CCS plants will only become

interesting to investors when the allowance price is at least € 40/tCO_2. Only then will the potential revenues be sufficient to offset the additional investment costs for CCS power plants in an acceptable time frame.

- Increasing the share of renewable energy will cause price effects, which will make refinancing more difficult for CCS power plants. On the other hand, price effects of CCS power plants will decrease the revenues for renewable energy, which in turn will have impacts on the level of renewable energy surcharges (EEG surcharges).

7.5 Summary and Conclusions

The costs of capturing CO_2 increase the plant costs in three ways: (1) costs for additional plant components, e.g. CO_2 compression; (2) costs for additional plant capacity to compensate for efficiency losses if net capacity is to be kept at the same level; (3) costs for additional fuel due to efficiency losses.

The plant costs for CCS power plants still involve uncertainties, despite the continuing development of demonstration facilities. An increasing understanding and ongoing technological development means that the investment costs of the first commercial CCS plants are predicted to be much higher than in previous studies. The investment costs for CCS power plants tend to be around 70–90 % higher than for conventional plants without CCS. The costs for the transportation and storage of CO_2 depend on the quantities to be transported, the transport distance, and the type and location of the geological storage facility, and they vary considerably. In all cases, the costs of capturing CO_2 dominate.

Even for high plant utilization, much higher electricity generation costs arise. With an increase of up to 80 % (lignite), coal-based CCS plants are particularly affected. The CO_2 avoidance costs are € 34–38/tCO_2 for lignite plants, € 41–48/tCO_2 for hard coal plants, and approx. € 67/tCO_2 for natural gas plants. Only when the price of allowances rises to the same level will the use of CCS power plants be cost-effective.

Variations of ±10 % in the individual process and cost parameters (full-load hours, efficiency, fuel, and purchase prices) lead to moderate changes in the generation costs for CCS plants of approx. € 2–4/MWh. A corresponding variation in the price of CO_2, in contrast, is not significant due to the low specific CO_2 emissions. A very low number of full-load hours (~2,500 h) tends to cause the CO_2 avoidance costs to double. As a result, a relatively high CO_2 price would be necessary to justify the implementation of the CCS technologies described here for a low number of full-load hours.

CCS power plants must be refinanced through the electricity market. Furthermore, the use of CCS power plants can have an effect on the price of electricity on the wholesale market under certain conditions. Assuming perfect competition, the price on the electricity market is determined by the costs of the last power plant used, whereby the order in which the power plants are used is based on their marginal costs (merit order) and the costs for electricity imports must be considered. For high allowance prices (e.g. € 30/tCO_2), the operating costs of CCS power plants are below those of a comparable coal-fired power plant. The price of electricity, particularly during periods of low electricity demand, is determined by the costs of coal power plants. During these periods, the use of CCS dampens the price of electricity. Lower electricity generation costs domestically lead to a drop in electricity imports and a rise in electricity exports.

In general, the question arises as to the degree to which higher revenues due to merit order effects can cover the additional investment costs for CCS power plants. Owing to the high uncertainties with respect to the additional investment costs for CCS plants, it can be assumed that they will only become interesting to investors when the allowance price is at least € 40/tCO_2. The development in the area of renewable energy must also be considered here. As long as sufficient 'cheap' backup capacities, i.e. power plants with low operating costs, are available, the increased use of renewables will lead to a decrease in the average annual price on the electricity market. In addition, merit order effects occur. The use of CCS also dampens the price of electricity and thus boosts the level of domestic production. It must be noted that price effects caused by the increased use of renewable energy will make refinancing for CCS power plants more difficult, and the price effects of CCS power plants will decrease the revenues for renewable energy, which in turn will have impacts on the level of EEG surcharges.

If renewable energy is further integrated into the current electricity market design ('energy only'), there is a danger that the power plant capacities of an existing fleet will be potentially underused. In addition to the generation cost effect caused by a low number of full-load hours, the drop in residual demand would lead to a merit order effect. As a result, there would be a short-term cost recovery problem for fossil plants in the installed power plant fleet. Regardless of the possible concrete development of capacity markets, the comparatively high refinancing needs compared to conventional power plants will remain if capacity revenues are to be incorporated.

Appendix

LCOE

LCOE according to Global CCS Institute (2009), supplemented with a cost term for CO_2 allowances (IEA NEA OECD 2010):

$$LCOE\,[€/MWh] = \frac{CRF \cdot I + F_{FOM} \cdot C_{FOM}}{CF \cdot E_{Annual}} + F_{VOM} \cdot C_{VOM} + F_{Fuel} \cdot C_{Fuel} + F_{Carb} \cdot C_{Carb}$$

$$CRF = \frac{i}{1-(1+i)^{-n}} \quad \text{(Capital Recovery Factor)}$$

$$F_j = \frac{K_j\left(1-K_j^n\right)}{A\left(1-K_j\right)} \quad \text{(Levelisation Factor)};$$

$$A = \frac{(1+i)^n - 1}{i(1+i)^n} \quad \text{(Present Value Factor)}; \quad K_j = \frac{1+R_j}{1+i} \quad \text{(Escalation Factor)}$$

with i = interest rate

and

F_{FOM} = Levelisation Factor fix O + M

F_{VOM} = Levelisation Factor variable O + M

F_{Fuel} = Levelisation Factor Fuel

F_{Carb} = Levelisation Factor CO_2

R_j = Escalation rate for cost j (excluding inflation)

CAC

$$CAC\,[€/t\,CO_2] = \frac{EGC_{CCS} - EGC_{REF}}{CO_{2,REF} - CO_{2,CCS}} + C_{Carb}$$

Where

EGC_{CCS}: energy generation costs of a plant with carbon capture,
EGC_{REF}: energy generation costs of the plant without carbon capture,
$CO_{2,REF}$: specific CO_2 emissions without carbon capture,
$CO_{2,CCS}$: specific CO_2 emissions with carbon capture

Learning Curves

Learning Curve

$K = K_0 \cdot X^{-E}$ with E: Learning index; X: cumulative capacity

Progress Rate

$PR = 2^{-E}$ Cost development with doubling capacity

Learning Rate

$LR = 1 - PR$

$$\Rightarrow E = -\frac{\ln(1-LR)}{\ln 2}$$

Methodological Approach for Merit Order Analyses

The methodological approach is based on the assumption of full competition on the electricity market. The price of electricity is regulated there depending on supply and demand. The price of electricity is determined by the marginal costs of the most expensive power plant needed to cover demand. The target function of the optimization formulation is thus:

$$\min Z_t = \sum_n \sum_i c_i \cdot s_{i,n,t} \cdot X_{i,n} + \sum_n \sum_m c_l imp_{n,m,t}$$

where

t: time index []
n, m: country index
i: index for power plant type
c_i: electricity generation costs of power plant type i [€/MWh]
$s_{i,n,t}$: utilization of power plant type i in country n at time t, where $0 \leq s_{i,n,t} \leq 1$ []
$X_{i,n}$: installed capacity of power plant type i in country n [MW]
c_l: costs for exchange of electricity [€/MWh]
$imp_{n,m,t}$: net imports of electricity from country n to country m [€/MWh]

A secondary condition here is that demand must always be covered.

$$\sum_i s_{i,n,t} \cdot X_{i,n} + \sum_m imp_{n,m,t} \geq d_{n,t} \qquad \forall n$$

In addition, electricity import and export capacities must be considered.

$$imp_{n,m,t} \leq NTC_{n,m} \qquad \forall (n,m)$$

with

$NTC_{n,m}$: net transfer capacities.

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