



# The potential of renewables versus natural gas with CO<sub>2</sub> capture and storage for power generation under CO<sub>2</sub> constraints



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## ABSTRACT

The costs of intermittent renewable energy systems (IRES) and power storage technologies are compared on a level playing field to those of natural gas combined cycle power plants with CO<sub>2</sub> capture and storage (NGCC–CCS). To account for technological progress over time, an “experience curve” approach is used to project future levelised costs of electricity (LCOE) based on technology progress ratios and deployment rates in worldwide energy scenarios, together with European energy and technology cost estimates. Under base case assumptions, the LCOE in 2040 for baseload NGCC–CCS plants is estimated to be 71 €/2012/MWh. In contrast, the LCOE for electricity generated intermittently from IRES is estimated at 68, 82, and 104 €/2012/MWh for concentrated solar power, offshore wind, and photovoltaic systems, respectively. Considering uncertainties in costs, deployment rates and geographical conditions, LCOE ranges for IRES are wider than for NGCC–CCS. We also assess energy storage technologies versus NGCC–CCS as backup options for IRES. Here, for base case assumptions NGCC–CCS with an LCOE of 90 €/2012/MWh in 2040 is more costly than pumped hydro storage (PHS) or compressed air and energy storage (CAES) with LCOEs of 57 and 88 €/2012/MWh, respectively. Projected costs for battery backup are 78, 149, and 321 €/2012/MWh for Zn–Br, ZEBRA, and Li-ion battery systems, respectively. Finally, we compare four stylised low-carbon systems on a common basis (including all ancillary costs for IRES). In the 2040 base case, the system employing only NGCC–CCS has the lowest LCOE and lowest cost of CO<sub>2</sub> avoided with CO<sub>2</sub> emissions of 45 kg/MWh. A zero CO<sub>2</sub> emission system with IRES plus PHS as backup is 42% more expensive in terms of LCOE, and 13% more costly than a system with IRES plus NGCC–CCS backup with emissions of 23 kg CO<sub>2</sub>/MWh. Sensitivity results and study limitations are fully discussed within the paper.

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**Abbreviations:** CAES, compressed air energy storage; CC, combined cycle; CCS, CO<sub>2</sub> capture and storage; CF, capacity factor; CHP, combined heat and power production; CSP, concentrated solar power; LCOE, levelised cost of electricity; EPC, Engineering, Procurement, and Construction; ETP, Energy Technology Perspectives (biannual study published by IEA); ETS, greenhouse gas emission allowance trading scheme; EU, European Union; EWEA, European wind energy association; FGD, flue gas desulphurisation; GHG, greenhouse gas; HHV, higher heating value; IDC, interest during construction; IEA, International Energy Agency; IGCC, integrated gasification combined cycle power plant on coal (and biomass); IPCC, Intergovernmental Panel on Climate Change; LHV, lower heating value; NGCC, natural gas combined cycle power plant; NPV, net present value; O&M, operating and maintenance; PC, ultra supercritical pulverised coal (and biomass) fired power plant; PHS, pumped hydro storage; ppm(v), parts per million – by volume; PR, progress ratio; PV, photovoltaic systems; IRES, intermittent renewable electricity generation technologies; TCR, total capital requirement; UCED, unit commitment and economic dispatch; WEO, World Energy Outlook (yearly study published by IEA)

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## 1. Introduction

Based on scientific assessments of “dangerous anthropogenic interference with the climate system”, public institutions have set targets to limit the average worldwide surface temperature increase to no more than 2 °C compared to pre-industrial levels. This target is often translated to one of the stabilising atmospheric concentration of GHGs to around 450 ppm CO<sub>2</sub> equivalent by the end of this century [1]. That would require global CO<sub>2</sub> emissions to be reduced drastically (e.g., 50–85% by mid-century). CO<sub>2</sub> emission mitigation scenarios envision different portfolios of low-carbon technologies to achieve those large reductions.

Natural gas fired combined cycle power plants (NGCCs) can be a first step in reducing CO<sub>2</sub> emissions by about 50% compared to coal-fired power plants. To achieve greater reductions, NGCC with CO<sub>2</sub> capture and storage (CCS) (either as a retrofit technology or on new builds) could be an important low-carbon technology option. However, the role of NGCC-CCS in CO<sub>2</sub> mitigation scenarios is still uncertain. For example, its role in scenarios in which fossil fuel power is phased out completely ranges from 0% [2,3] to 36% of total global electricity production [4]. In energy scenarios, NGCC-CCS can

either contribute substantially to baseload power generation, or provide backup capacity in a portfolio rich with intermittent renewable electricity systems (IRES) [5]. IRES technologies have the advantage of generating power without depleting natural resources. On the other hand, their power generation is variable, partially unpredictable, and controllable only to a limited extent [6,7].

Ultimately, deployment of low-carbon NGCC-CCS power will depend on its cost-effectiveness relative to alternative low-carbon power generation technologies. Important competitors for baseload operation in a mitigation portfolio are IRES technologies like photovoltaics (PV), wind power (onshore and offshore), and concentrated solar power (CSP) used in conjunction with a thermal storage system to increase its availability and control. Other low-carbon competitors for baseload operation include hydropower, geothermal, coal-fired CCS power plants, biomass-fired power generation and nuclear power [5]. Alternatives that compete with NGCC-CCS for backup capacity include pumped hydro storage, compressed air energy storage (CAES), and power storage systems based on batteries [5,8].

To plan R&D activities and demonstration projects related to NGCC-CCS development, it is important to get more insight into

its potential role in the power generation mix. For comparisons of baseload options, the requirement of a level playing field implies that the cost of IRES should also include the additional costs incurred due to extra balancing services, extra transmission requirements, and adequacy requirements [9,10]. Such a comparison of NGCC–CCS and IRES, including all these costs and how they may develop over time, has not yet been done.<sup>1</sup> Furthermore, a systematic cost comparison of NGCC–CCS with power storage technologies as backup capacity for IRES also is lacking.<sup>2</sup> The present study addresses these two gaps in the low-carbon energy systems literature.

The objective of this paper is to get insights into the cost-effectiveness of NGCC–CCS compared to IRES and power storage technologies as a CO<sub>2</sub> mitigation strategy. Therefore, we address the following three research questions in this study:

- What are the potential cost reductions for each technology due to future learning?
- How does the cost of NGCC–CCS compare to the cost of IRES when they are each operated to their full extent for baseload power generation?
- How does the cost of NGCC–CCS compare to the cost of power storage over time in providing backup services in low-carbon systems with large shares of intermittent renewables?

The starting point for this study was to establish a level playing field for an in-depth analysis focussed on a limited number of technologies. Besides NGCC–CCS, we selected three IRES options, namely, offshore wind, PV, and CSP. We also selected five energy storage technologies, namely, PSH, CAES, lithium ion, ZEBRA, and Zn–Br battery systems. CSP is only partly intermittent because it can also be designed as a controllable technology by adding thermal storage systems. When we mention “IRES” and “power storage technologies” in this study we refer to these specific technologies.

Since most low-carbon technologies above are still in the early stages of commercialization and deployment there is significant potential for cost reductions as the technologies mature. Several studies, e.g. [11,12], have investigated the “experience curve” concept for energy technologies and identified so-called progress ratios (PRs) – a parameter expressing the fraction of the original unit cost of a technology after a doubling of its cumulative production or installed capacity. Thus, a PR of 0.90 means that the unit cost (e.g., euros/kW) falls to 90% of its previous value with each doubling of installed capacity. (The PR is directly related to the learning rate, LR, which is the fractional reduction in cost for each doubling of capacity; thus, in the example above LR=0.1, or 10%). This study employs the experience curve approach to assess potential cost reductions over the next several decades. Using an inventory of historical PRs (based on empirical cost data) and current cost estimates for the energy technologies of interest, the future cost of each technology is projected as a function of its future deployment.

We assess the cost of technologies in Europe and consider the period from 2011 to 2050. We assume that learning takes place at a global level, and use projections of global cumulative capacities

of each technology to derive potential cost reductions. Because decision-makers also seek projections into cost developments for shorter time horizons, we also highlight cost estimates in 2020, 2030, and 2040. All cost estimates are based on scenarios that assume a policy framework in which deep CO<sub>2</sub> emission reduction targets are set. Following the presentation of our analysis we discuss the implications of key assumptions employed.

## 2. Method

### 2.1. Introduction

As noted earlier, an important aspect of this study is to compare technologies on a level playing field. Thus, the cost of the IRES should include integration costs needed to deal with specific characteristics of renewable technologies. PV and offshore wind power generation are characterized by variability and a degree of unpredictability. They are often deployed at spatially dispersed and unevenly distributed locations. CSP with thermal storage is more predictable and can be regulated, but may be located far from load demands. We define integration costs as the additional costs compared to an electricity generation system in which intermittent renewable generation is replaced by a hypothetical alternative system that is fully controllable, predictable, and can be constructed easily along the existing grid.<sup>3</sup>

Integration costs consist of three components, namely:

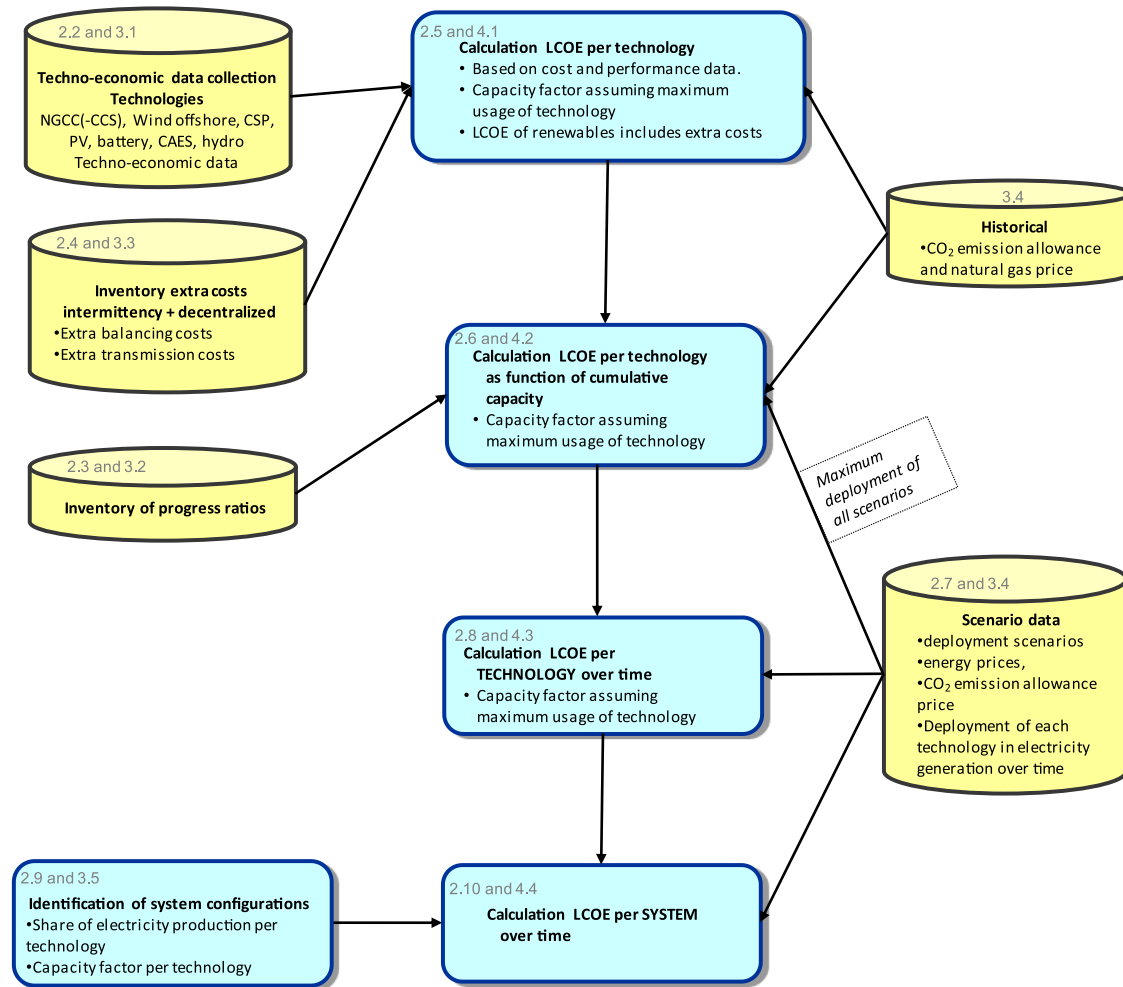
1. *Balancing costs.* These are additional costs to match supply and demand on a short-term basis. They include the cost of extra reserve requirements (primary and secondary reserves), and other costs to deal with the variable and unpredictable aspects of intermittent renewable generation. For example, other power plants may have to run at lower part-load efficiencies, or start/stop more often, which induces extra costs.
2. *Transmission costs.* These include grid expansion costs required to connect the more spatially dispersed and unevenly distributed renewable generation technologies to the grid.
3. *Adequacy costs.* These costs are for backup or storage capacity needed when there is insufficient intermittent renewable electricity generation. Usually, these technologies operate at low capacity factors. The adequacy costs include both the investment costs of the backup or storage capacity and the incremental costs of running at a lower capacity factor than in the case without intermittency.

Fig. 1 shows an overview of the study methodology. The yellow shapes refer to the inventory of data activities, and the blue boxes to the calculations of levelised cost of electricity (LCOE). The calculations are all implemented in the Microsoft Excel spreadsheet application (referred to as the Excel model hereafter). LCOE is a widely-used metric for reporting and comparing the cost of power generation technologies [13,14], though it must be used carefully when both baseload, load-following, and intermittent technologies are involved. Unlike load-following units (e.g. an NGCC–CCS plant that operates whenever needed), IRES does not provide power on demand but on an intermittent basis. Therefore, throughout this study the LCOE of an IRES option is expressed as €/MWh<sub>int</sub>, where the subscript “int” refers to electricity generated intermittently.

<sup>1</sup> A review by Larsson et al. [9] of 12 studies which assessed electricity production costs shows that these studies did not compare costs of NGCC–CCS and IRES on a level playing field including a projection into the future. Viebahn et al. [118] compared cost development of offshore wind and NGCC–CCS, but did not add integration costs.

<sup>2</sup> Numerous studies compared power storage technologies with respect to their technical characteristics without addressing costs (e.g. [119,120]) and other studies also included cost aspects [43,121] but did not compare these to those of other backup technologies like NGCC.

<sup>3</sup> This definition is based on a definition presented by Meibom et al. [72]. Note, that the most cost-effective generation mix system beside the intermittent generation or ‘theoretical’ alternative generation may consist of different technologies. The comparison is, therefore, simplified.



**Fig. 1.** Scheme of the method (the numbers refer to the different sections in the method section, data section, and result section) (For interpretation of the references to colour in this figure, the reader is referred to the web version of this article.)

In the first three LCOE calculations (see blue boxes 2.5, 2.6, and 2.8), the LCOEs of NGCC and NGCC-CCS are calculated assuming they are operated as either baseload or load-following units. In these sections, the “stand-alone” LCOEs of individual IRES include the extra balancing and transmission costs required for IRES. However, to be able to properly compare the LCOEs of IRES with NGCC-CCS for situations including base load operation, power system configurations that provide similar levels of service including adequacy services also need to be investigated. For this reason, the costs of different base load power system configurations are also assessed (box 2.10). These configurations are based on current load patterns without demand-side management measures.

All costs are presented in constant €<sub>2012</sub>. Capacity units (kW, MW, GW) refer to net power output and energy units (kWh, MWh) refer to net electricity output unless otherwise stated.

## 2.2. Techno-economic data collection

Data collection is based on the common method of cost estimation for CCS at fossil fuel power plants as specified in Rubin et al. [15], who address the problem of inconsistent costing methods for CCS technologies currently employed by various organizations. They establish a recommended method for estimating capital and O&M costs, and for calculating the levelised cost of electricity (LCOE). The method of Rubin et al. [15] was adopted for this study to assess costs of other technologies than CCS power plants as well.

The specific cost parameters which were collected for each technology comprise capital investment cost, and operation & maintenance (O&M) costs. Cost parameters for NGCC-CCS include costs of CO<sub>2</sub> transport and storage. Cost parameters of IRES include those related to extra balancing and transmission. Finally, efficiency parameters for all NGCC options and CAES are collected to determine fuel costs, CO<sub>2</sub> emissions, and associated costs for a given CO<sub>2</sub> price. In each case, it was verified that capital and O&M cost parameters included all cost elements as specified in the cost estimation method of Rubin et al. [15]. Because the most recent year for which cost data are available differed per technology, the base year for learning varies by technology between 2010 and 2012 in this study.

### 2.2.1. Capital cost

The capital cost parameter is based on the total capital requirement (TCR), which includes process equipment, supporting facilities, direct and indirect labour, engineering services, contingencies, owner's costs (including start-up and initial stock feed inventories), and interest during construction (IDC). A detailed description of the cost elements included in the TCR can be found in Rubin et al. [15].

### 2.2.2. O&M cost

The O&M cost comprises fixed O&M cost and variable O&M cost. The fixed O&M cost consist of labour cost (operation,



maintenance and administration & support), cost for maintenance materials, property taxes and insurance cost. The variable O&M cost includes costs for consumables other than fuel (e.g. chemicals, water and catalysts), waste disposal, and by-product sales.

### 2.2.3. Ranges of reported costs

Recent literature studies were used to collect techno-economic input data for this study. Many studies present data ranges to account for cost uncertainties, ranges in PRs, differences in geographical conditions across Europe and technology configurations (e.g. more or less heat storage in CSP systems). The techno-economic input data in this study were divided into optimistic, base case, and pessimistic values. The combination of optimistic values for a specific technology results in the lowest LCOE for this technology and vice versa.<sup>4</sup> The optimistic and pessimistic values represent the two end values of the data range observed in literature. The base case values are the averages of the input data found for a particular parameter (e.g. the investment cost parameter). The base case values are considered to be the most representative (best estimate) values for Europe on average. However, values could very well be lower or higher in particular regions in Europe.

### 2.3. Progress ratios for technological learning

In this study, technological learning is defined as the various mechanisms (such as learning-by-doing, learning-by-searching, learning-by-interacting, learning-by-using, upsizing and economies of scale) that influence both the production process and the product operation, resulting in technological change and cost reductions [16]. Numerous literature studies have investigated the phenomenon of technological learning with energy technologies by empirically observing a relationship between unit costs of production and cumulative production or installed capacity. This study does not seek to derive such empirical relationships, but rather identifies values for progress ratios (PRs) in literature for the energy technologies under study.<sup>5</sup> Both Junginger et al. [16] and Azevedo et al. [17] conducted a comprehensive literature review for energy generation technologies and observed a broad range of PRs mainly for capital costs of NGCC–CCS, PV, CSP, and onshore wind energy technology. Junginger et al. [16] have shown that derived PRs can vary significantly for a particular energy technology due to differences in underlying data sets and geographical scope. Moreover, many studies base their analysis on data sets of other studies, which do not result in ‘original’ PRs. Therefore, only studies presenting PRs based on original data sets were used for the analysis in this paper.

<sup>4</sup> In some cases, an optimistic value for a specific cost parameter may be higher than the pessimistic value, but the associated LCOE is lower. For example, higher investment costs of CSP result in a higher capacity factor and associated lower LCOE.

<sup>5</sup> PRs derived from empirical cost data can differ considerably among energy technologies. For example, unitary cost of PV modules have been observed to decline with a PR of 80% over the past four decades, whereas higher PRs (90–96%) have been determined for offshore wind turbines over a period of around 15 years [16]. As yet, scientific literature has not been able to give clear explanations as to why these differences exist. A likely explanation given by Junginger [122] could be that technologies with a high number of product output and a modular nature that can be easily standardized (e.g. PV), have low, i.e. more favourable, PRs than technologies with a relatively low output number, which are more complex and thus more difficult to standardize (e.g. offshore wind). High output volumes and standardization are factors that are conducive to production process optimization and will logically result in more learning-by-doing and economies of scale.

### 2.4. Extra costs related to intermittency and decentralisation

An inventory of extra balancing costs was assembled based on a literature review in which these costs were preferably calculated in a power system simulation model. Such models should: I. simulate the power system on an hourly basis (or smaller time step), II. include the reserve market, interconnection capacities, and storage options, III. model the variability and partial unpredictability of the intermittent renewable energy sources, and IV. account for flexibility parameters of the generators (i.e. partial load efficiencies, start-up costs, ramp-up and down rates, minimum down time, startup time, and minimum partial load capacity).

### 2.5. Calculation of LCOE per technology

The levelised cost of electricity (LCOE) is a constant unit price used for comparing the costs of energy technologies having different fuel mixes, capital costs, annual costs, net outputs, and economic lifetimes [15]. In this study the cost of electricity for individual IRES also includes additional costs for balancing and transmission. In the Excel model, the LCOE is calculated using Eq. (1).

$$LCOE = \frac{TCR \cdot \alpha + FOC}{8.76 \cdot CF} + \frac{COF \cdot 3.6}{\eta} + VOC + C_{CO_2} + C_{BAL+TRAN} + C_{CO_2 T\&S} \quad (1)$$

with  $\alpha = r / (1 - (1 + r)^{-L})$

where TCR is total capital requirement (in €/kW),  $\alpha$  is the annuity factor (%), FOC is the fixed O&M cost (€/kW per year), COF is the cost of fuel (€/GJ),  $VOC_{NGCC-CCS}$  is the variable O&M cost for the NGCC–CCS plant (€/MWh),  $C_{BAL+TRAN}$  is the cost for balancing IRES and extra transmission costs for IRES (€/MWh),  $C_{CO_2 T\&S}$  is the cost of CO<sub>2</sub> transport and storage (in the case of CCS),  $C_{CO_2}$  is the cost of CO<sub>2</sub> emission allowances in case CO<sub>2</sub> is emitted (in €/tonne CO<sub>2</sub>), CF is the capacity factor,  $\eta$  is the energy efficiency (in MWh<sub>out</sub>/MWh<sub>in</sub>),  $r$  is the real discount rate (%), and  $L$  is the economic lifetime (years).

### 2.6. Calculation of LCOE per technology as function of cumulative capacity

The capital costs, O&M costs, PRs and cumulative installed capacities of the energy technologies, as well as prices for natural gas and CO<sub>2</sub>, can be used to derive the quantitative relation between cumulative capacity and LCOE (see Eq. (2)).

$$C_i = C_{i=1} \cdot Cum_i^b \quad (2)$$

$$PR = 2^b \Rightarrow b = \log_2 PR \quad (3)$$

$Cum_i$  is the cumulative capacity of a technology ( $i$  GW),  $C_i$  is the cost for the  $i$ th GW of the cumulative capacity,  $C_{i=1}$  is the cost for the first GW of the cumulative capacity, and  $b$  is the experience index.

On the basis of PR, and cost data and cumulative capacity for the starting year per technology, we derived ‘ $b$ ’ and  $C_{i=1}$  for each technology. Next, we plotted the LCOE as a function of the cumulative capacity starting at the base year of the technology up to its maximum cumulative capacity potential in 2050. Since learning takes place at a global scale, we use global projections of the cumulative capacity (see Section 3.5 below). For each technology, the maximum deployment worldwide in 2050 was taken to be the maximum installed capacity in 2050 found in different global scenarios. The reductions in LCOE as a function of cumulative capacity were calculated based on the base case techno-economic parameters and PRs. Capacity factors were set at their

maximum, i.e. the availability factor to show the maximum achievable cost reductions for each technology.

## 2.7. Inventory of scenario data

As the aim of the research is to assess the role of NGCC–CCS in a climate mitigation strategy, we collected global deployment data from scenarios in which the worldwide average temperature increase is kept below 2 °C compared to pre-industrial levels. This target is usually translated to a target of stabilising the concentration of atmospheric GHGs at 450 ppmv by the end of this century. Various GHG emission scenarios are modelled in the literature to achieve that objective.

## 2.8. Calculation of LCOE per technology over time

The LCOE over time is determined by combining the quantitative relations between cumulative capacity and the cost components of LCOE. In this case, we link the cumulative capacity  $i$  to a specific year  $t$  (compare Eqs. (2) and (4)) based on the deployment of technologies in global mitigation scenarios (see Section 3.5).

$$C_t = C_{t=0} * Cum_t^b \quad (4)$$

The LCOEs are presented from the base year of the technology to 2050.

## 2.9. Definition of system configurations

In order to show the competitiveness of the technologies in the electricity system, we have to take into account the system adequacy requirements discussed earlier. As a consequence, capacity factors are lower than the maximum availability factor. Secondly, in a situation with IRES, more capacity has to be installed than without IRES for adequacy requirements. Finally, in a system with IRES, power storage and limits on electricity generation from certain IRES technologies may be necessary.

To compare the competitiveness of the technologies under study including costs for adequacy requirements, we defined four stylized systems of electricity generation technologies and storage technologies as presented in Table 1. Note, that the worldwide energy scenarios show that future power systems will consist of many more technologies than included in these systems. The LCOEs which result from this exercise can, therefore, be interpreted as the costs of an isolated (and simplified) system in a world where only these energy technologies are deployed to meet one of the selected global mitigation scenarios.

The stylized systems are characterized by their yearly capacity factors and the shares of each technology in electricity generation (as a % of electricity demand). The first three systems are based on the electricity demand pattern and the wind and solar supply patterns in the Netherlands, as a representative North European country. Using these patterns in the MARKAL-NL-UU model [18], we estimated capacity factors and shares of electricity generation per technology. MARKAL formulates a technology-rich energy model into a linear programming (LP) problem. This LP problem is solved by the CPLEX solver to calculate the technological configurations and dispatch in the system by minimizing the net present value of all system costs

[19]. Capacity factors of the fourth system, which consists only of IRES with power storage, are taken from Ehler, who modelled this system in detail with a power system simulation model [20].

## 2.10. Calculation LCOE per system

In the Excel model, we first calculated the LCOE per year of each stylized system using the best estimate values of the techno-economic parameters. Later we examined the effect on LCOEs of uncertainty in the various input parameters.

## 3. Data inventory

### 3.1. Techno-economic input data

#### 3.1.1. Natural gas combined cycle (NGCC) with and without CO<sub>2</sub> capture (CCS)

The performance parameters are based on four literature studies [21–24] presenting, inter alia, efficiencies and cost estimates for typical NGCC–CCS plants in Europe for the reference year 2011. Table 2 presents the techno-economic input data used to calculate the LCOE for NGCC and NGCC–CCS. The data sets underlying the referenced studies have been populated mainly with data on existing power plants, pre-FEED studies and/or vendor quotes. The data applied to NGCC plants with net capacity sizes in the range of 420–910 MW (w/o CO<sub>2</sub> capture) and 350–804 MW (with CO<sub>2</sub> capture), respectively. Plant efficiencies were found to be 54–58% w/o CO<sub>2</sub> capture and 46–50% with CO<sub>2</sub> capture, both on a LHV basis, whereas the availability factors varied between 80% and 93% [22,23]. The total capital requirement of combined cycles are found to be in the range of 650–1080 €/kW and 650–1245 €/kW for NGCC without CO<sub>2</sub> capture and the combined cycle part in a NGCC–CCS plant, respectively. The fixed and variable operation and maintenance costs range from 7–12 €/kW/y and 2.1–3.8 €/MWh, respectively.

The CCS plants are assumed to use post-combustion capture systems employing conventional, advanced [21] or proprietary amine systems [22]; no specific solvent was mentioned in Parsons Brinckerhoff [23]. CO<sub>2</sub> capture ratios varied between 86% and 90%, whereas the discharge temperature and pressure of the CO<sub>2</sub> stream was 30 °C and in the range of 100–120 bar. The total capital requirement of the CO<sub>2</sub> capture system and compression unit are 400–795 €/kW and 35–70 €/kW,<sup>6</sup> respectively. The fixed and variable O&M costs show ranges of 21–38 €/kW and 2.9–5.4 €/MWh, respectively; the wide range of the variable O&M costs is mainly due to the uncertainty in the costs for the consumables. The energy needed for solvent regeneration, fans, pumps, and CO<sub>2</sub> treatment (drying, purification and cooling) were reported to be 2700 MJ/t CO<sub>2</sub> and 294 MJ/t CO<sub>2</sub> (23.5 MWe) and the electricity use for CO<sub>2</sub> compression (26.5 MWe) was 331 MJ/t CO<sub>2</sub> [22]. Cost data for CO<sub>2</sub> transport and storage were taken from the Zero Emissions Platform [25,26]. The cost ranges presented are mainly due to the various transport conditions (on- and offshore pipelines, volumes (2.5–20 Mt per year) and distances (180–1500 km)) as well as storage conditions (on- and offshore, depleted gas/oil reservoirs and saline aquifers, field capacity and well injection rates, new and existing wells, liability transfer costs), and to a lesser degree to uncertainty in the cost elements [25,26].

<sup>6</sup> The outlier value for the compressor and dehydration unit (217 €/kW) derived from Maas et al. [24] was excluded from the cost range, as it was considered to be unrealistically high.

**Table 1**  
Systems included in comparison.

Type of system	Baseload	Units providing adequacy services
NGCC–CCS	NGCC–CCS	–
IRES/NGCC	Mix of wind and PV	NGCC
IRES/NGCC–CCS	Mix of wind and PV	NGCC–CCS
IRES/storage	Mix of wind and PV	PHS

**Table 2**

Techno-economic input data for NGCC–CCS for the year 2011 for net capacity units. Data are taken from [21–24], unless otherwise stated.

Parameter	Unit	Optimistic	Base case	Pessimistic
Plant efficiency (LHV) without CCS <sup>a</sup>	%	58	56	54
Plant efficiency (LHV) with CCS <sup>a</sup>	%	50	48	46
CO <sub>2</sub> capture ratio <sup>b</sup>	%	86	88	90
TCR <sup>c,d</sup>				
NGCC (single plant)	k€/kW	0.59	0.79	0.95
NGCC (part of NGCC–CCS plant)	k€/kW	0.62	0.86	1.22
CO <sub>2</sub> capture component	k€/kW	0.40	0.59	1.14
Compression unit	k€/kW	0.03	0.04	0.07
Fixed O&M costs <sup>e</sup>				
NGCC <sup>f</sup>	€/kW/y	6	9	11
NGCC–CCS <sup>f</sup>	€/kW/y	12	17	22
Variable O&M cost <sup>e</sup>				
NGCC	€/MWh	1.9	2.7	3.6
NGCC–CCS <sup>g</sup>	€/MWh	4.1	5.9	7.7
Variable O&M costs for transport & storage <sup>h</sup>	€/MWh	3	7	11

<sup>a</sup> The net power plant efficiencies (LHV) were indicated by the IEA GHG [22], Parsons Brinckerhoff [23] and ZEP [21] to be 59, 57–60, and 60% for NGCC and 51–52, 47.5–50.0 and 52% for NGCC with CO<sub>2</sub> capture, respectively. These values were considered to be too optimistic given the current power plant efficiencies for NGCC [49]. Therefore, values were used of Maas et al. [24] and Van den Broek et al. [54] of 56% and 48% for NGCC and NGCC with CO<sub>2</sub> capture, respectively.

<sup>b</sup> The low end value originate from ZEP [21]; the other three studies indicated a capture ratio of 90%.

<sup>c</sup> The low and high end values for the TCR stem from the IEA GHG [22] and Parsons Brinckerhoff [23], respectively. The values originating from Maas et al. [24] and ZEP [21] were in between these values. The base case TCR are average values based on the four aforementioned studies used for input data. Except for ZEP [21], none of the studies included interest during construction (IDC). We assumed a loan interest rate of 6% and adopted the following investment cost phasing from CESAR [83] for NGCC: year 1: 40%; year 2: 30%; year 3: 30%, resulting in an IDC of 13% of underlying investment cost data. Similarly, the following investment cost phasing from the IEA GHG [22] was used for NGCC–CCS: year 1: 15%; year 2: 35%; year 3: 40%; year 4: 10%. This resulted in an IDC of 16% of underlying investment cost data.

<sup>d</sup> Includes costs for pre-licensing and contingency costs (25% for labour, 5–10% on direct materials, 25% for profit on labour).

<sup>e</sup> The ratio between fixed and variable O&M cost differed between Maas et al. [24], ZEP [21], IEA GHG [22] and Parsons Brinckerhoff [23], which is likely due to different assumptions on the long term service agreements. The total O&M cost (M €/y) of the four studies were, however, rather similar when using a similar base case availability factor (86.5%) and NGCC plant size (700 MW). The average of the total O&M cost (M€/y) and the ratio between fixed and variable O&M cost of Maas et al. [24] were used to acquire the average fixed and variable O&M cost of the four referenced studies. These average numbers were used for the base case values in this study. The low and high end values for the O&M cost were chosen by using the uncertainty range of  $\pm 30\%$  as indicated by Maas et al. [24].

<sup>f</sup> Routine maintenance and long term service agreement costs.

<sup>g</sup> Consumables needed for the CO<sub>2</sub> capture process.

<sup>h</sup> Based on data from ZEP [25,26].

### 3.1.2. Offshore wind

Table 3 presents the techno-economic input data used to calculate the LCOE for offshore wind energy. The techno-economic input data were taken from two literature studies [27,28], which cover a wide range of wind turbine sizes (2–5 MW), wind farm sizes (100–500 MW), water depths (up to 30 m) and distances to shore (up to 30 km). The cost data presented in the studies stem mainly from offshore UK wind projects under development, tender prices, supplier quotes, and the views of developers, equipment manufacturers, Engineering, Procurement, and Construction (EPC) contractors, and other relevant stakeholders. The data apply to the reference year 2011. Although the wide cost ranges result mainly from project-specific conditions, they also reflect the uncertainty in cost. It should be mentioned that capital costs increased over the last five years as a result of technical challenges as well as higher demand for equipment and service markets, which pushed up EPC prices

**Table 3**

Techno-economic input data for offshore wind energy for the year 2011. Cost data are based on [27,28].

Parameter	Unit	Optimistic	Base case	Pessimistic
Capacity factor 2011 <sup>a</sup>	%	34	40	46
Capacity factor 2050 <sup>b</sup>	%	40	45	50
TCR <sup>c</sup>	k€/kW	2.15	3.43	4.22
Fixed O&M costs <sup>d</sup>	€/kW	97	151	264

<sup>a</sup> The capacity factor range for 2011 is based on Lemming et al. [84] and ECN [85], who indicated capacity ranges for offshore wind in Europe to be in the range of 35–45% and 34–46%, respectively; ECN [85] indicated an average value of 40%.

<sup>b</sup> An average capacity factor of 45% was projected for Europe by the European Wind Energy Association (EWEA) [86] for 2050. The offshore wind database of the NREL [87] gives detailed figures for the offshore wind energy potential across Europe and the associated capacity factors. The NREL [87] reports that the largest potential offshore wind is in areas with high capacity factors (> 46%); therefore, a value of 50% was used for the high end value; the conservative value of 40% was based on ECN [85], who assumed no improvement in the average capacity factor up till the year 2050.

<sup>c</sup> Both the low and high end values originate from ARUP [28]; values from Mott MacDonald [27] fell within this range. Data from Mott MacDonald [27] includes contractors' contingencies but not developers' own contingencies. Also, these data exclude IDC. We assumed a loan real interest rate of 6% and adopted the following investment cost phasing from PWC [88]: year 1: 5%; year 2: 10%; year 3: 35%; year 4: 50%. This resulted in an IDC of 10.5% of underlying investment cost data. Although the report from ARUP [28] did not specify all cost categories as specified by Rubin et al. [15], we assumed they were included in the cost assessment.

<sup>d</sup> The low end value is from Mott MacDonald [27], whereas the high end value stems from ARUP [28]. These costs include O&M services from wind turbine suppliers, vessel hire and other O&M support and labour costs. While Mott MacDonald [27] excluded cost for insurances and grid charges (to recoup the grid connection costs), ARUP [28] did incorporate these costs, but did not quantify the amount.

[27]. This market congestion premium is expected to disappear over time once the supply chains are able to meet demand.

### 3.1.3. Photovoltaic solar energy

Table 4 presents the techno-economic input data used to calculate the LCOE for PV. The data were taken from the PV simulation tool of the PV Parity project, which makes cost projections for PV systems in several European countries<sup>7</sup> and is based on data from local manufacturers and stakeholders [29,30]. The tool accounts for the variation in the average energy yields across Europe. The extracted data on PV systems applies to the year 2012 and pertains to both households (3.5 kW) and industry (100 kW). The cost range is mainly due to varying system sizes, PV module prices and installation cost across European countries. The input data pertains to silicon crystalline modules, which is currently the dominant PV technology in Europe.

### 3.1.4. Concentrated solar power

Table 5 presents the techno-economic input data used to calculate the LCOE for CSP. The techno-economic input data found in literature is often difficult to compare and standardize due to site-specific conditions (direct normal irradiation,<sup>8</sup> temperature, etc.), type of solar thermal collectors (parabolic trough, linear fresnel, solar tower, parabolic dishes), cooling method (dry or wet cooling), heat fluid (thermo-oil, salt, steam), and plant capacity factor. The last factor depends heavily on if and how much thermal storage is applied or co-firing is assumed, which directly influences the size and design of

<sup>7</sup> Austria, Belgium (Flanders and Wallonia), Czech Republic, France (North and South), Germany (North and South), Greece (North and South), Italy (North and South), Portugal, Spain (North and South), the Netherlands and the UK.

<sup>8</sup> The Direct Normal Irradiation (DNI) is "the amount of solar radiation received per unit area by a surface perpendicular (normal) to the rays that come in a straight line from the direction of the sun at its current position in the sky" in kWh/m<sup>2</sup> [123].



**Table 4**

Techno-economic input data for solar photovoltaic (PV) for the year 2012. Data are based on the PV simulation tool of the PV parity project<sup>a</sup> [30].

Parameter	Unit	Optimistic	Base case	Pessimistic
Capacity factor	%	20	14	12
TCR <sup>b</sup>	k€/kW <sub>p</sub>	1.80	2.00	2.40
Fixed O&M costs <sup>c</sup>	€/kW <sub>p</sub>	27	25	30

<sup>a</sup> Based on the data from the PV simulation tool, the LCOEs were calculated for each country. The techno-economic data of the most pessimistic case (highest LCOE) represents a PV household system in Austria, and the most optimistic (lowest LCOE) an industrial PV system in Spain. The outlier values on total PV system costs (3500–5200 €/kW in France, 2400–3025 €/kW in Belgium and 2400–2700 €/kW in the UK) from the PV Parity tool were excluded from the input data ranges as these were considered to be unrepresentative for the European case. Instead, values were included from SolarNRG [90] and CMS [91], which presented PV system cost of 1800–2100 €/kW (4 kW<sub>p</sub> system) for Belgium and 2100 €/kW (4 kW<sub>p</sub> system) for the UK, respectively. The PV system cost for France were excluded from the analysis.

<sup>b</sup> Total PV system costs contains costs for PV modules, converter, installation, installation, connection, commercialization [89].

<sup>c</sup> Operating costs for solar PV include insurance, operation and maintenance, and provisions for inverter replacement [89].

**Table 5**

Techno-economic input data for concentrated solar power parabolic troughs and solar towers for the year 2010. Data are based on [38,39,92].

Parameter	Unit	Optimistic	Base case	Pessimistic
<b>CSP SM1, 0 h storage (CF 19%)</b>				
TCR <sup>a,b</sup>	k€/kW <sub>p</sub>	2.83	4.04	5.25
Fixed O&M costs <sup>b</sup>	€/kW/yr	38	54	71
<b>CSP SM2, 6–9 h storage (CF 41%)</b>				
TCR <sup>a,c</sup>	k€/kW <sub>p</sub>	4.91	6.65	9.12
Fixed O&M costs <sup>c</sup>	€/kW/yr	10	34	71
<b>CSP SM3, 9–15 h storage (CF 61%)</b>				
TCR plant SM3, 9–15 h storage <sup>a,c</sup>	k€/kW <sub>p</sub>	6.42	8.47	10.71
Fixed O&M costs <sup>c</sup>	€/kW/yr	12	27	46
<b>CSP SM4, 15–21 h storage (CF85%)</b>				
TCR <sup>a,d</sup>	k€/kW <sub>p</sub>	8.10	11.57	15.04
Fixed O&M costs <sup>e</sup>	€/kW/yr	16	37	64

<sup>a</sup> None of the underlying studies indicated whether cost for IDC were included; it was assumed these costs were not incorporated. The construction period for CSP plants was reported to be 1–3 years, depending on the technology (parabolic troughs or solar towers) [52]. As no CAPEX phasing was found in literature, we assumed the following CAPEX phasing from CESAR [83] for NGCC plants to apply to CSP plants as well: year 1: 40%; year 2: 30%; year 3: 30%, resulting in an IDC of 13% (based on a loan interest rate of 6%), which was added to the total CAPEX.

<sup>b</sup> Values were taken from Turchi et al. [39].

<sup>c</sup> Average values were taken from Turchi et al. [39] and Fichtner [38].

<sup>d</sup> Values for TCR were taken from Trieb et al. [92].

<sup>e</sup> OPEX values were indicated by Trieb et al. [92] to be 2.5% of TCR. However, we assumed a similar OPEX–TCR ratio (0.2–1.5%) was used as assumed by Turchi et al. [39] and Fichtner [38] for reasons of consistency among the different CSP plant configurations.

the solar field in relation to the generator capacity, expressed by the solar multiple (SM) [31]. CSP plants with higher storage capacities and/or co-firing options are more flexible in terms of electricity production and less limited by the inhomogeneous diurnal and seasonal solar irradiation pattern. However, CSP plants with higher storage capacity entail higher capital costs, assuming a constant generator size. The plant design will be determined by the function it will have to replace in the current electricity system, i.e. providing peak power (low storage), load-following power (base case storage) or baseload power (high storage) [31].

Several studies indicated that a trend towards higher storage capacities is expected for the future [32,33]. As the plant configurations are difficult to compare, it was decided to adopt the approach of Trieb et al. [34] by making cost projections for four different configurations types, each with its own collector field and storage capacity size, but with a similar generator capacity. Most CSP plants in Europe are built in the centre and South of Spain due to the high DNI value (DNI > 2000 kWh/m<sup>2</sup>/y). Locations with a DNI value lower than 1800 kWh/m<sup>2</sup>/y are currently not economically interesting for a CSP plant [31,35,36]; however, this might change in the future with decreasing capital and O&M costs. Most plant configurations in Europe have a storage capacity of 0–8 h (SM1 and SM2), with an exception for the Gemasolar solar tower in the South of Spain, which has a storage capacity of 15 h (SM3) [37]. The LCOE range was determined by using the TCR, O&M cost and capacity factors associated with the different plant configurations types (SM1, SM2, and SM3), each with its own collector field and storage capacity size, but with a similar generator capacity. The configuration type with SM4 was excluded from the analysis as this type has as yet not been built. Data from literature on European CSP plants are mostly outdated; therefore, data from US studies [38,39] were used instead.<sup>9</sup> The data applies to the emerging solar tower technology and the parabolic trough technology. The latter accounts for the largest share of the current CSP market [40].

### 3.1.5. Power storage technologies

The techno-economic input data for the energy storage technologies are presented in Table 6. pumped hydro storage (PHS), compressed air energy storage (CAES) and lithium-ion (Li-ion) batteries are considered to be mature commercial technologies, whereas ZEBRA (Sodium–Nickel–Chloride, NaNiCl) and Zinc–Bromine (ZnBr) flow batteries are still in their infancy and not yet fully developed. PHS and CAES are both systems with high storage capacities, low self-discharge, long technical lifetimes, and high cycle life,<sup>10</sup> which make them apt for supporting utility systems with varying loads during the daily cycle. The response times are seconds to minutes for PHS and 5–15 min for CAES [41]. Unlike conventional batteries, which have short cycle life and low energy density (lead acid batteries) or high environmental impact and memory effect (nickel cadmium batteries), Li-ion, ZEBRA and ZnBr batteries are advanced technologies that are suitable for renewable energy storage. They also have significant improvement potential in terms of techno-economic performance [41,42]. Li-ion, ZEBRA and ZnBr batteries display shorter response time (milliseconds) than PHS and CAES and can, therefore, sustain frequent power delivery and storage cycles. However, battery capacities are usually much smaller than for PHS and CAES. The promising Zn–Br flow batteries are particularly interesting as they can be scaled up to very large capacities by adding more electrolytes combined in series or in parallel [43]. The relatively low energy density (60–80 Wh/kg) renders Zn–Br batteries more suitable for stationary than for transportation purposes, whereas Li-ion and ZEBRA can be used for both purposes [8,41]. Potential applications of Zn–Br batteries are to support renewables, peak-shaving, back-up supply and power supply [41]. Although several other flow battery types show promise, Zn–Br batteries were selected for this study because of their favourable techno-

<sup>9</sup> Capital costs for CSP plants in Europe and the US are currently converging and are expected to become (almost) similar in the near future [124].

<sup>10</sup> The cycle life defined as the number of ‘discharge/charge’ cycles that an energy storage system can experience before it fails to meet specific performance criteria (based on Gerssen-Gondelach and Faaij [42]). Note that the cycle life for batteries is highly dependent on the level of discharge during each cycle; for this reason, the cycle life is often quoted together with the Depth of Discharge (DoD). A DoD of 100% means that a battery is fully discharged [42].



**Table 6**  
Performance data for energy storage technologies<sup>a</sup>

Parameter	Unit	PHS <sup>c</sup>	CAES	Li-ion	ZEBRA	ZnBr
Efficiency	%	75–85	70–90	85–95	90	65–75
Capacity	MW	100–5000	5–400	1*10 <sup>-3</sup> –40	1*10 <sup>-3</sup> –53	5*10 <sup>-3</sup> –100
Energy density	Wh/kg	0.5–1.5	30–60	75–600	125–790	60–80
Life time	Years	40–100	20–40	5–15	10–15	5–20
	Cycles	13*10 <sup>3</sup> –50*10 <sup>3</sup>	5*10 <sup>3</sup> –20*10 <sup>3</sup>	1*10 <sup>3</sup> –5*10 <sup>3</sup>	> 2500	> 2000
Response time		sec–min	5–15 min	ms	ms	ms
TCR <sup>b</sup>	k€/kW	2.10–2.58	0.55–1.70	5.50–5.85	2.18–4.82	1.27–2.17
	k€/kWh <sub>stor</sub>	0.13–0.32	0.07–0.34	1.09–1.95	0.44–0.96	0.25–0.43
Fixed O&M cost <sup>b,d</sup>	€/kW/yr	34–40	25–34	66–75	35–70	22–47
Variable O&M cost <sup>b</sup>	€/MWh	0.6	6.7–8.6	2.0–3.3	0.9–2.0	1.1–2.5
Maturity		Mature	Com.	Com.	Demo	Demo

<sup>a</sup> Data based on values of [8,41,42,46,47].

<sup>b</sup> Cost ranges are based on vendor quotes in the US [8]. The cost ranges represent the full investment cost of the storage systems and are presented both in € per kW discharge capacity and in kWh storage capacity. These should not be added together.

<sup>c</sup> The cost values presented for PHS apply to greenfield plants, and not to the retrofit of existing hydropower plants.

<sup>d</sup> Fixed O&M includes major maintenance: every 20 years for PHS and every 4–7 years for CAES. Including battery replacement battery cost; every 5 or 15 years for Li-ion and every 8 or 15 years for ZEBRA; no replacement cost was included for ZnBr batteries. The number of years depend on the specific type, which can be different for each vendor [8].

economic features. In general, it should be borne in mind that cost projections on future battery technologies (ZEBRA, ZnBr) are more uncertain than the projections for commercial battery technologies (Li-ion).

Limited lithium reserves are sometimes indicated as a potential barrier to large-scale deployment of Li-ion batteries. Gaines and Nelson [44] conclude that even with aggressive deployment of light-weight vehicles based on Li-ion batteries, known lithium supplies would suffice for decades, provided a high level of recycling is instituted. According to Gerssen-Gondelach and Faaij [42], lithium demand could exceed the world base reserves under very extreme conditions. Thus, they emphasise the necessity of recycling, as do Andersson and Råde [45]. Including larger vehicles with higher driving ranges in the electric drive fleet would strongly increase demand for lithium, which could eventually strain lithium supplies [44], and result in concomitant price premiums. The constituent materials nickel (used both in Li-ion and ZEBRA batteries) and zinc (Zn–Br batteries), may face scarcity problems when used at a very large scale; Andersson and Råde [45] foresee that conventional nickel resources will be depleted by 2050, and that its availability for batteries will depend predominantly on demand from other sectors and the discovery of new, low-cost resources. Recycling of metals will therefore be essential to ensure material availability.

Data for power storage technologies in Table 6 were taken from a variety of sources that provide data on systems in Europe as well as the US [8,41,42,46,47]. The large ranges observed for the techno-economic performance data result from different project requirements, uncertainties for novel battery technologies, and differences in operational parameters, market indicators, prices and tariffs used in the sources underlying the referenced studies.

### 3.1.6. Financial factors

The input values used for the real discount rate and economic lifetime have a large impact on the calculated levelised cost of electricity. The values chosen for these parameters should therefore be carefully assessed.

**3.1.6.1. Real discount rate.** The real discount rate mirrors the risk perception of developers, lenders and investors. In this study, the real discount rate reflects the risk perspective of a private, unregulated company. Discount rates are usually higher for nascent technologies, such as CCS and offshore wind, than for mature and proven technologies, such as gas-fired power plants,

which entail lower technical risks. Growing experience with emerging technologies will lower the risks and instill confidence in investors, resulting in lower discount rates over time. The literature reports wide ranges of discount rates. Oxera [48] identified ranges for real discount rates for a series of low-carbon generation technologies for the year 2011. To do this, they assessed the main underlying drivers, taking into account both technological and market risks derived from the literature and a survey of industry participants [48]. Despite this analysis, uncertainty remains on the values of discount rates. Therefore, it was decided to use a standard value of 10% in the analysis over the entire period (2011–2050). The ranges identified by Oxera [48] are used in the sensitivity analysis to demonstrate the impact of the technology-specific real discount rates on the final results. An overview of the real discount rates as presented in Oxera [48] is given in Table 7 for NGCC, NGCC–CCS, offshore wind, and PV. The remaining technologies were taken from other sources.

**3.1.6.2. Economic lifetime.** The economic life time is the period over which the technology is depreciated, which is often subject to rules or approval of the government, such as a minimum time for depreciation. The economic lifetime does not necessarily reflect the technical plant life, which can be significantly longer [49]. Table 8 presents an overview of the values used for the economic lifetime in this study. The values were taken from literature; the low and high end values were assumed to be five to ten years below and above the base case value, respectively. The selected ranges are in agreement with economic lifetimes reported in other studies [21,24,27,28,38–41,46,50–52].<sup>11</sup> The impact of the economic lifetime on the final results is discussed further in the sensitivity analysis.

### 3.2. Progress ratios

#### 3.2.1. NGCC–CCS

Two studies derived learning effects from original data of NGCC plant technology. Colpier and Cornland [53] derived PRs of 90% for the specific investment costs and 94% for the O&M costs in the maturity stage of the technology. A log–linear relationship between energy loss based on higher heating value ( $1 - \text{efficiency}_{\text{HHV}}$ ) in an

<sup>11</sup> An exception exists for PHS and CAES. The lifetime value ranges indicated by Evans et al. [46] and JRC [41] are 40–60 and 50–100 years for PSH, and 20–40 and 25–40 years for CAES, respectively. A smaller range was used in this study.

**Table 7**

Ranges of real discount rates for the year 2010–2012 (depending on the technology) as presented in [48], unless otherwise stated.

Technology	2010–2012		
	Optimistic	Base case	Pessimistic
NGCC	6	7.5	9
NGCC–CCS	12	14.5	17
Offshore wind	10	12	14
PV	6	7.5	9
CSP <sup>a</sup>	10	12	15
PHS <sup>b</sup>	6	7.5	9
CAES <sup>c</sup>	12	14.5	17
Li-ion <sup>d</sup>	8	10	12
ZEBRA and ZnBr batteries <sup>e</sup>	12	14.5	17

<sup>a</sup> The Energy Technologies Perspectives of the IEA [76] presented ranges of observed real discount rates for inter alia CSP of 10–15%, respectively. The ranges were based on discussions with various financial institutions.

<sup>b</sup> Mott MacDonald [27] and Guzman [93] used a real discount rate of 7.5% and 7% for hydropower projects and pumped hydro storage, respectively. Oxera [48] indicated a real discount rate range of 6–9% for run-of-the-river hydropower plants. The real discount rate is expected to be low as large-scale hydropower is a well-developed, long-term proven, technology with few operational risks.

<sup>c</sup> Oxera [48] did not report real discount rates for CAES systems. As only two compressed air facilities are in operation today [41], the technology is not yet mature. Similar to NGCC–CCS, a range of 12–17% was used for this study.

<sup>d</sup> Van Vliet et al. [94], Budischak [95] and Gerssen-Gondelach and Faaij [42] employed a real discount rate of 10% for lithium-ion batteries. This value is deemed realistic given the fact that the Li-ion battery is a mature technology.

<sup>e</sup> The large risks associated with early development technologies, such as the ZEBRA and ZnBr battery systems, result in high real discount rates. Similar to NGCC–CCS, a range of 12–17% was used for this study.

**Table 8**

Ranges of economic lifetime used for this study.

Technology	2010–2012			Reference
	Pessimistic	Base case	Optimistic	
NGCC	20	25	30	[22,96]
NGCC–CCS	20	25	30	[22,96]
Offshore wind	15	20	25	[97]
PV <sup>a</sup>	20	25	30	[85]
CSP	20	25	30	[85]
PHS	50	60	70	[8]
CAES	15	20	25	[98]
Batteries <sup>b</sup>	10	15	20	[8]

<sup>a</sup> Hernández-Moro and Martínez-Duart [51] state that most PV producers warrant their systems for a duration of 25–30 years (based on [99,100]).

<sup>b</sup> DOE/EPRI [8] indicates a lifetime of 15 years for the Li-ion, ZEBRA and ZnBr battery storage systems (including power conversion electronics, monitoring and control systems, physical enclosure, miscellaneous switchgear and hardware to connect to the grid of customer load). The lifetime applies to the storage systems, not to intermediate battery replacement, which is sometimes required.

NGCC power plant and its cumulative capacity with a PR of 95% was found by Van den Broek et al. [54]. Rubin et al. [55] derived a PR for flue gas desulphurisation units (FGD) to serve as a reasonable guide to future rates of technological progress in post-combustion amine systems due to the many similarities between these technologies. Both systems can be used as a post-combustion control technology using chemical agents [56]. The PRs are 89% and 78% for the capital cost and O&M cost, respectively, of the amine CO<sub>2</sub> capture system. By analogy with energy efficiency improvements observed for cryogenic air separation units, the PR for reduced energy consumption of the CO<sub>2</sub> capture process was set at 95% [56]. Improvements in energy consumption are expected to come mainly from the advent of advanced solvents [54]. Peeters et al. [57] argued that only limited scope exists for technological learning in the conventional compression process, as the technology is already mature and

optimized. However, cost reductions from unit standardisation and innovative compressor technologies may still be possible if CCS is deployed at a large scale. An example of a novel compressor technology is the supersonic shock wave compressor, which is currently under development and shows potential for cost reductions [58–60]. This study assumes a PR of 97.5% as the base case value for the compressor technology. Ramírez et al. [61] report several opportunities for reductions in pipeline costs, such as shifting to alternative steel types, use of higher strength materials and economies of scale. Nevertheless, it is very difficult to quantify such cost reductions. Also, if CCS were deployed at a large scale, operators would have to resort increasingly to more distant and less favourable storage sites, which would at least partly offset potential cost reductions. For this reason, no technological learning was assumed for CO<sub>2</sub> transport and storage.

### 3.2.2. Offshore wind

To date, three studies have utilized the experience curve method to explore past and future price reductions of offshore wind farms [16]. ECN [62] and Isles [63] report PRs to be in the range of 90–96% and 90%, respectively. Junginger et al. [11] produced a more detailed analysis by applying the experience curve method to individual components of offshore wind farms – offshore turbines, grid connection and installation – to derive respective PR ranges of 81–85%, 62–71% and 77–95%. Unfortunately, the aggregated capital costs input data of offshore wind farms used for the base year did not allow us to perform a detailed component-based analysis. Instead, the PRs of ECN [62] and Isles [63] were used for TCR. There is still significant potential for learning in both capital and O&M cost [64] and PRs of both are expected to be similar [65]. However, the expected decrease in O&M cost may be partly offset by the development of wind turbines being built further offshore, which will make maintenance trips to the turbine parks more expensive. Therefore, similar PRs are assumed for capital and O&M costs [65].

### 3.2.3. PV

Most experience curve studies for PV investigate technological learning for the PV module or cell price, whereas only one study [12] looked into balance-of-system (BOS) components (i.e. inverter, supports and cables). Experience curves are mainly based on price data rather than cost data, because the latter are extremely difficult to obtain. Substantial differences can be observed in the reported PR values (65–95%), which depend heavily on the time period of the underlying data sets used. Experience curve analyses spanning long time series (around four decades) will probably yield the most reliable PR values, which are around 80% [11]. Schaeffer et al. [12] found PR values of  $77.9 \pm 1.1\%$  and 81% for the BOS cost for Germany and the Netherlands, respectively, over the period 1992–2001. A base case value of 80% for the PR of the entire PV system was used in this study.

### 3.2.4. CSP

The limited amount of CSP capacity installed worldwide has made the construction of experience curves rather difficult. A study by Enermodal [66], which was based on data for capital costs for CSP plants installed in California, reports a PR of 88%. However, as noted by Junginger et al. [16], reliable PRs can only be derived after many doublings of the cumulative installed capacity. As there have been at most three doublings in capacity, it was recommended to use a range of PRs (85–92%) rather than one value [66]. Although other (more recent) publications on technological learning are available, none of them derived PRs from historical data. Nor did experience curves establish quantitative relations between O&M costs and cumulative production and/or

capacity. Although Kolb et al. [67] reports that O&M costs can be curtailed through improved automation and better O&M techniques, no quantitative reduction potential was given. Thus, no technological learning was assumed for O&M costs in this study.

### 3.2.5. Power storage

The low penetration rate and large cost range of pumped hydro storage (PHS) and compressed air energy storage (CAES) have made it very difficult to construct experience curves for these technologies. A PR of 90% was assumed for energy storage technologies in general in the bottom-up energy system model ReMIND [68]. Efforts to make experience curves for battery technology were more successful. Nagelhout and Ros [69] observed a PR of 83% for lithium-ion cells for consumer electronics. For nickel–metal–hydride batteries, PRs of 89.8% [70] and 91% [71] were identified. A PR range of 85–95% was assumed for all

energy storage technologies. The PR for Li-ion battery systems is assumed to be higher than the PR observed by Nagelhout and Ros [69] for batteries alone, since the overall system, which consists of multiple components (e.g. batteries, power conversion electronics, monitoring and control systems, physical enclosure, miscellaneous switchgear and hardware to connect to the grid of customer load), probably does not learn as fast as the battery component by itself. Also, no technological learning was assumed for O&M costs for the five storage technologies included in this study.

### 3.2.6. Summary

Table 9 presents a summary of the PR value ranges used in this study. The PRs for the TCR are all related to cumulative installed capacity (in GW), except for the batteries which apply to cumulative installed energy storage capacity (in GWh). In Tables 16–18 in Annex I, all base case, optimistic, and pessimistic values are presented in separate tables.

## 3.3. Extra costs for balancing and transmission

### 3.3.1. Balancing costs

Table 10 presents balancing costs found in the literature review. These range from 0–6.1 €/MWh<sub>int</sub> for wind penetration rates up to 35%. In our study we use 3 €/MWh<sub>int</sub> as a base case value.

The studies mentioned are in general not explicit about which aspects (e.g. ramping rate, partial load efficiencies, etc.) are included and how. Meibom et al. [72] found that with increasing wind penetration rates, the balancing costs increase per MWh<sub>int</sub>. Furthermore, they noted that in regions with high capacities of hydropower balancing costs are lower, because its flexibility parameters are favourable (i.e. low start-up costs, low part-load operation, no restrictions on ramp-up and ramp down rates).

Most of the studies have calculated the balancing costs for wind integration in systems without power plants with CCS. Integration of a combination of PV with wind can possibly reduce the balancing costs as wind, and solar PV power generation patterns are weakly correlated, which leads to smoothing of the combined power production [6,73,74].

**Table 9**

Summary of progress ratios used in this study.

Technology	TCR			OPEX			Energy loss		
	Opt.	Base	Pes.	Opt.	Base	Pes.	Opt.	Base	Pes.
NGCC <sup>a</sup>	85	90	95	90	94	100	92	95	98
CO <sub>2</sub> capture unit <sup>a</sup>	83	89	94	70	78	90	92	95	98
CO <sub>2</sub> compression unit	95	97.5	100	–	–	–	–	–	–
Offshore wind	86	90	94	86	90	94	–	–	–
PV <sup>b</sup>	75	80	85	100	100	100	–	–	–
CSP	85	88	92	100	100	100	–	–	–
PHS <sup>c</sup>	85	90	95	100	100	100	100	100	100
CAES <sup>c</sup>	85	90	95	100	100	100	100	100	100
Batteries <sup>c</sup>	85	90	95	100	100	100	100	100	100

<sup>a</sup> The PR ranges for costs of NGCC and CO<sub>2</sub> capture unit are based on IEA GHG [56] and for energy loss on Van den Broek et al. [54].

<sup>b</sup> The low and high end values for the PR range of the TCR for PV are based on the distribution of derived PRs calculated over various time periods as presented by Nemet GF [101].

<sup>c</sup> The low and high end values for the PR ranges of the TCR for power storage technologies are based on own assumptions. No improvements in efficiency of these technologies were taken into account.

**Table 10**

Overview of balancing costs found in the literature.

Wind penetration	Costs (in €/MWh <sub>int</sub> )		Calculation method	Reference
	min	max		
35%	2.5	6.1	The increase in reserve costs of a unit commitment and economic dispatch (UCED) simulation between a scenario without and a scenario with wind <sup>a</sup>	[102]
4–19%	0.9	5.1	Size of extra reserves is calculated statistically and multiplied by the simplified costs of reserves	[75], based on [103]
25%	–0.1	0.2	Size of extra primary reserves is determined statistically and multiplied by the calculated cost supply curve of reserves for the ERCOT area <sup>b</sup>	[104]
20%	3.6		The increase in costs from a UCED simulation with perfect foresight from a simulation that accounts for a forecast error of wind	[105]
25%	0.5		The cost effect of increasing the combined reserve size from 5% of peak load to 75% of peak load is simulated with a UCED model	[106]
< 20%	1.1	4.4	Review of literature up until 2008	[75]
20%	0.0	5.3	Review of literature up until 2005	[107]
10–13%	2.2	3.1	Costs are based on the difference in costs for CO <sub>2</sub> , startup, fuel costs, fuel startup, and O&M compared to system with 5% wind penetration	[105]
6% – 31%	0.2	3.1	The increase in costs compared to a scenario with 100% predictability and no variability <sup>c</sup>	[72]
Not available	0.7	5.2	Stated in World Energy Outlook without reference	[78]

Partly based on Brouwer et al. [6]:

<sup>a</sup> Detailed figures are based on the original source, which is the PhD thesis of the author [108].

<sup>b</sup> Costs are low because only primary reserves are considered. Higher wind penetrations lead to cheaper units providing regulation reserve, which results in a decrease in costs compared to the reference (0% wind) case.

<sup>c</sup> Wind penetration rate is ratio between average wind power production and the sum of transmission capacity and average power demand. It takes into account interconnection capacities, and transmission bottlenecks in certain regions.

**Table 11**

Extra transmission investment costs to integrate intermittent renewables into the grid.

Intermittency share <sup>a</sup>	Costs (in €/MWh <sub>int</sub> )		Description of costs	Reference
	min	max		
35%	2.5	5.0	Extra costs for wind (grid reinforcements). Review of literature up until 2007 <sup>b</sup>	[102]
20%	2.7	5.2	Extra costs for wind (grid reinforcements). Based on estimates of National Grid, the TSO of UK	[103]
15–3%	1.4	7.0	Extra costs for wind. Review of literature up until 2008 <sup>b</sup>	[75]
n.a.	1.6	10.1	Extra costs for IRES (grid connection, reinforcement, lower usage, longer distances)	[78]
10–913%	0.6	3.0	Grid re-inforcements to handle additional power flows from wind on the grid	[105]
29%	4.3		Extra investments in transmission and distribution grid for renewables <sup>c</sup>	[76]
n.a.	2.1	26.3	Extra costs for IRES due to longer average transmission distances (with 10% undersea transmission)	[109]

n.a., not available.

<sup>a</sup> Intermittency share is ratio between electricity generated by IRES and total electricity generation in one year.<sup>b</sup> Converted from €/kW to €/MWh<sub>int</sub> assuming a 40 year life time, discount rate of 7%, and an annual load factor of 35%.<sup>c</sup> In the ETP, the world is divided into 6 regions (OECD Europe, OECD Americas, OECD Asia Oceania, India, China, and other non-OECD). Calculations are based on the extra grid investment costs for renewables in the OECD regions (assuming life time of 40 years and discount rate of 7%).

### 3.3.2. Transmission costs

Table 11 presents the transmission investment costs. These also show a large range (1–26 €/MWh<sub>int</sub> for wind penetration rates up to 53%). This is mainly caused by different assumptions about the distances between wind turbines and the existing grid and/or electricity demand centres, and also about the capacity factor of wind. In this study, we use 5.5 €/MWh<sub>int</sub>, the average of the figures in Table 11.

Again most of the studies calculated the extra transmission costs for integration of wind energy. Costs for PV may be different. In general costs presented showed an increase in transmission costs per MWh<sub>int</sub> for higher penetration rates. However, a US overview study found that for higher penetration rates, costs went down because of economies of scale [75].

### 3.4. Inventory of scenarios

Many energy scenarios with a 450 ppm target have been created, like the 44<sup>12</sup> pathways in the Global Energy Assessment (GEA) [4], and one scenario in Energy Technologies Perspectives 2012 [76]. To assess the role of NGCC–CCS, we required deployment scenarios of the electricity generation technologies. Unfortunately, only ETP 2012 [76] provides the deployment rates of the technologies in GW, and, therefore, this publication has our preference. However, ETP 2012 provides only one 450-ppm scenario. GEA [4], conversely, presents a wide range of pathways giving a good overview of how climate targets can be met with different technology portfolios. They group their pathways with respect to three rates of efficiency improvement, namely, the efficiency pathways with high rates of efficiency improvement (i.e. primary energy consumption grows from 490 EJ in 2005 to 700 EJ in 2050), the supply pathways with low rates (i.e. 1050 EJ in 2050), and the mix pathways with an average rate (with 920 EJ in 2050). In all their pathways, population grows from 7 billion to 9 billion in 2050 after which it starts declining. Average worldwide economic growth is projected to be 2% per year in the next 50 years. Furthermore, they classify their pathways into two groups with respect to transport: conventional, in which transport remains liquid-based, and advanced, in which a shift can be made to electric or hydrogen transport.

Fig. 2 presents ranges for the number of doublings of IRES and NGCC-based technologies over a wide range of deployment scenarios in the GEA pathways and ETP 450-ppm scenario.<sup>13</sup> In

this study we focus on two GEA pathways, namely, “Image-mix”—called *HIGH-NGCC-CCS* in this study—which has a large role for NGCC–CCS; and “GEA-efficiency conventional transport,—no BECCS, no sinks, limited biomass”—called *HIGH-REN* in this study—which has a large role for IRES. As a base scenario, we use the “2 degrees” scenario of the ETP 2012 study—called *BASE 450* in this study—which has an intermediate role for both NGCC–CCS and IRES.

The GEA pathways only present the electricity production figures per technology over time. The capacities and capacity factors per technology, although they are determined in the GEA energy models, have not been published. For this reason, we used the capacity factors of the *BASE 450* (of the ETP 2012 study) to deduce the capacities of the technologies in the GEA pathways. In *BASE 450*, the capacity factors of CSP and PV increase over time from 16% and 10% in 2009 to 37% and 16% in 2050, respectively. The capacity factor of gas-fired power in ETP 2012 reduces from 38% in 2009 to 27% in 2050. The resulting capacity deployment of these 3 scenarios is shown in Figs. 10–12 in Annex II.

GEA and IEA did not quantify the power storage capacity requirements in the global energy systems. In order to estimate the storage capacity in the different scenarios, we deduced a ratio between storage capacity and intermittent capacity from two studies that explicitly included and reported the storage capacity used in their power system simulation modelling. Pöyry [77] found a ratio of 0.09–0.22 kW<sub>storage</sub>/kW<sub>IRES</sub> to be sufficient in scenarios with 55–77%<sup>14</sup> intermittent capacity in the UK. In Germany, Ehler [20] found ratios varying between 0.11 and 0.2 kW<sub>storage</sub>/kW<sub>IRES</sub> in scenarios with 46–82% intermittent capacity and a 0.33 kW<sub>storage</sub>/kW<sub>IRES</sub> ratio in a 100% intermittent capacity scenario. Based on these figures, we estimated that 0.2 kW storage capacity per kW of intermittent capacity would be sufficient for the *HIGH-REN* scenario with intermittent capacity increasing from 26% to 70% of total capacity between 2020 and 2050. Therefore, we used 0.2 kW<sub>storage</sub>/kW<sub>IRES</sub> to calculate storage capacity deployment and assumed that half of this capacity would be delivered by PHS, and the other half by CAES and batteries. The resulting cumulative capacities can be considered as the upper bound for the individual storage technologies. In the period before 2050 the intermittency capacity ratio is lower, and consequently, other power generation units are available to meet adequacy requirements. In the *HIGH-NGCC-CCS* scenario, we assumed that

(footnote continued)

to 35% higher) and 1 pathway has a 5% higher cumulative wind capacity by 2050 than the maxima used in this study.

<sup>14</sup> Storage capacity includes the capacity of batteries in electric vehicles. Total capacity includes the interconnection capacity. Intermittency includes marine capacity which may also include the more predictable tidal power capacity.<sup>12</sup> 41 Pathways with the MESSAGE model, and 3 with the IMAGE–TIMER model [4].<sup>13</sup> This range represents almost all GEA pathways and 450 ETP scenario. Only 4 pathways out of the 44 GEA pathways have a higher cumulative PV capacity (up



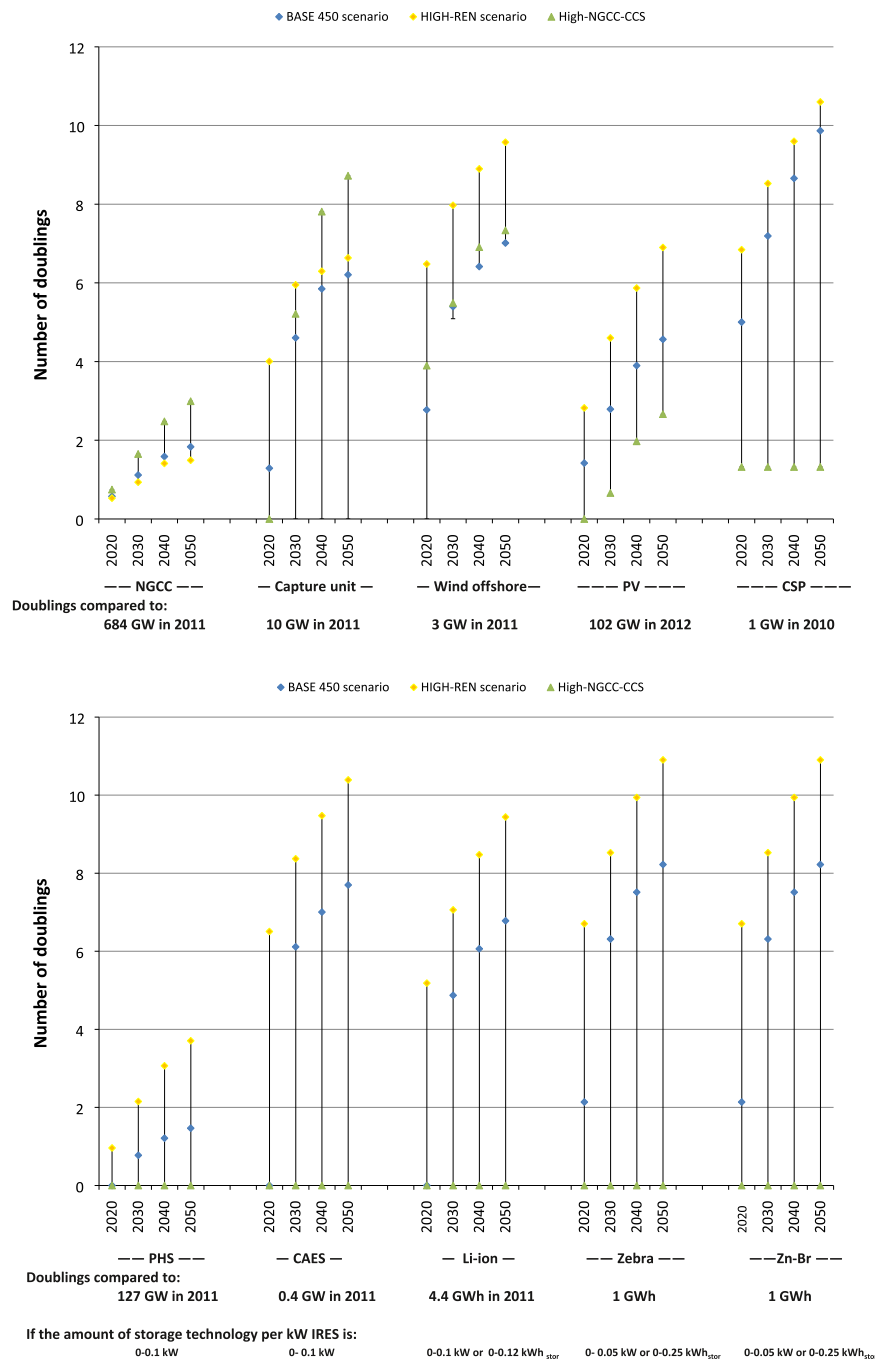


Fig. 2. The ranges of doublings of global cumulative capacity per technology in selected scenarios.

no power storage is needed, and in the *BASE 450* scenario  $0.1 \text{ kW}_{\text{storage}}/\text{kW}_{\text{IRES}}$ . In the period 2020–2050 intermittent capacity increased in these scenarios from 14% to 38% and 6% to 29%, respectively.

The maximum cumulative installed capacity for most power generation technologies is between 1.5–5.4 TW; PV has a higher cumulative capacity (12 TW), which originates from the *HIGH-REN* scenario.

### 3.4.1. Natural gas and CO<sub>2</sub> price development

Table 13 presents the natural gas and CO<sub>2</sub> price developments as used in this study. They are based on the 450-ppm scenario in the World Energy Outlook 2012 (WEO2012) [78] which are similar to the prices in the ETP-450 ppm scenario. GEA did not report any

prices. In the scenarios, the unit price on CO<sub>2</sub> emissions increases more than ten-fold by 2050. In turn, European gas prices increase through 2025, then gradually decrease to levels slightly below current prices by 2050 in response to decreased demand in a carbon-constrained world. In the sensitivity analysis, we also investigate a high price scenario in which natural gas prices continue to rise through 2050 (see Table 13) based on the Current Policy scenario in WEO2012.

### 3.5. Definition of system configurations

Fig. 3 presents the shares of the technologies and the capacity factors of the four stylized electricity systems. Capacity factors and electricity generation shares are based on our MARKAL runs (see Section 2.9) for the first three systems. Systems II and III are

**Table 12**  
Summary of cumulative capacity of the different technologies.

Technology	Base year techno-economic data	Base year cum. inst. capacity	Cum. inst. capacity base year	Max. cum. inst. capacity in 2050	Max. no. of doublings, in 2050
			GW	TW	
Combined cycle component	2011	2011	674 <sup>a</sup>	5.42 <sup>b</sup>	3.0
CO <sub>2</sub> capture unit	2011	2011	10 <sup>c</sup>	3.56 <sup>d</sup>	8.7
Offshore wind	2011	2011	3.0 <sup>e</sup>	4.12	9.6
PV	2012	2012	102 <sup>f</sup>	12.19	6.9
CSP	2010	2010	1.0 <sup>g</sup>	1.57	10.6
PHS	2010	2010	127 <sup>h</sup>	1.66 <sup>i</sup>	3.7
CAES	2011	2011	0.4 <sup>h</sup>	0.59	10.4
Li-ion batteries	2010	2013	4.4 GWh <sub>stor</sub> <sup>j</sup>	3.06 TW <sub>hor</sub>	9.4
ZEBRA, Zn-Br	2011		1 GWh <sub>stor</sub> <sup>k</sup>	1.82 TW <sub>hor</sub>	10.9

<sup>a</sup> Based on Watson [110] and the IEA [111].

<sup>b</sup> Maximum cumulative capacity includes NGCC components of both NGCC and NGCC-CCS. To deduce the NGCC deployment from gas-fired deployment, we assumed that the share of NGCC in gas-fired power grows from 47% in 2009 to 80% in 2050. Furthermore, we assumed that all gas-fired CCS consisted of NGCC-CCS technologies.

<sup>c</sup> Based on Van den Broek et al. `ADDIN CSL_CITATION { "citationItems": [ { "id": "ITEM-1", "itemData": { "DOI": "10.1016/j.pecs.2009.05.002", "ISSN": "0360-1285", "author": [ { "dropping-particle": "", "family": "Broek", "given": "Machteld", "non-dropping-particle": "van den", "parse-names": false, "suffix": "" }, { "dropping-particle": "", "family": "Hoeftagels", "given": "Ric", "non-dropping-particle": "", "parse-names": false, "suffix": "" }, { "dropping-particle": "", "family": "Rubin", "given": "Edward", "non-dropping-particle": "", "parse-names": false, "suffix": "" }, { "dropping-particle": "", "family": "Turkenburg", "given": "Wim", "non-dropping-particle": "", "parse-names": false, "suffix": "" }, { "dropping-particle": "", "family": "Faaij", "given": "Andr u00e9", "non-dropping-particle": "", "parse-names": false, "suffix": "" } ], "container-title": "Progress in Energy and Combustion Science", "id": "ITEM-1", "issue": "6", "issued": { "date-parts": [ [ "2009" ] ] }, "page": "457-480", "title": "Effects of technological learning on future cost and performance of power plants with CO2 capture", "type": "article-journal", "volume": "35", "uris": [ "http://www.mendeley.com/documents/?uid=8afd9b54-93c9-4df51-b502-0347e6bd17eb" ] }, "mendeley": { "previouslyFormattedCitation": "[54]" }, "properties": { "noteIndex": 0 }, "schema": "https://github.com/citation-style-language/schema/raw/master/csl-citation.json" }` [54].

<sup>d</sup> Cumulative capacity of post-combustion capture units include capture units of both NGCC-CCS and PC-CCS. No distinction is made in the scenarios regarding the type of capture at coal fired power plants. We assumed that in 2020 90% of coal-CCS plants would consist of PC-CCS diminishing to 70% in 2050. Other coal-CCS would be either oxyfuel based power plants or IGCC-CCS.

\* Based on GWEC ADDIN CSL-CITATION { "citationItems": [ { "id": "ITEM-1", "itemData": { "author": [ { "dropping-particle": "", "family": "GWEC", "given": "", "non-dropping-particle": "", "parse-names": false, "suffix": "" } ], "id": "ITEM-1", "issued": { "date-parts": [ [ "2013" ] ] }, "page": "72", "publisher-place": "Global Wind Energy Council, Brussels (Belgium)", "title": "Global Wind Report - Annual market update 2012", "type": "report" }, "uris": [ { "http://www.mendeley.com/documents/?uuid=df993f3f-bd80-4b38-b794-6cd495687e35" } ] }, "mendeley": { "previouslyFormattedCitation": "[112]", "properties": { "noteIndex": 0 }, "schema": "https://github.com/citation-style-language/schema/raw/master/csl-citation.json" } ] ]112}.

<sup>†</sup> Based on EPIA ADDIN CSL\_CITATION { "citationItems": [ { "id": "ITEM-1", "itemData": { "author": [ { "dropping-particle": "", "family": "EPIA", "given": "", "non-dropping-particle": "", "parse-names": false, "suffix": "" } ], "id": "ITEM-1", "issue": "May", "issued": { "date-parts": [ [ "2012" ] ] }, "page": "76", "publisher-place": "European Photovoltaic Industry Association, Brussels (Belgium)", "title": "Global Market Outlook for photovoltaics until 2016", "type": "report", "uris": [ "http://www.mendeley.com/documents/?uuid=807dd8f8-fcf9-4d26-b741-979a87dbb1f0" ] }, "mendeley": { "previouslyFormattedCitation": "[113]", "properties": { "noteIndex": 0 }, "schema": "https://github.com/citation-style-language/schema/raw/master/csl-citation.json" } ] ] [113].

<sup>8</sup> Based on CSP World ADDIN CSL\_CITATION { "citationItems": [ { "id": "ITEM-1", "itemData": { "URL": "http://www.csp-world.com/resources/csp-facts-figures", "accessed": { "date-parts": [ [ "2013", "6", "6" ] ], "author": [ { "dropping-particle": "", "family": "CSP World", "given": "", "non-dropping-particle": "", "parse-names": false, "suffix": "" }, { "id": "ITEM-1", "issued": { "date-parts": [ [ "2013" ] ], "title": "CSP Facts & Figures, URL": "http://www.csp-world.com/resources/csp-facts-figures. Visited: 06-06-2013", "type": "webpage" }, "uris": [ { "http://www.mendeley.com/documents/?uuid=a58cfd4f-d596-4ad8-b1c0-5e39dbf7e7e4" } ] }, "mendeley": { "previouslyFormattedCitation": "[114]" }, "properties": { "noteIndex": 0 }, "schema": "https://github.com/citation-style-language/schema/raw/master/csl-citation.json" } ] [114].

<sup>h</sup> Maximum cumulative capacity includes NGCC components of both NGCC and NGCC-CCS. To deduce the NGCC deployment from gas-fired deployment, we assumed that the share of NGCC in gas-fired power grows from 47% in 2009 to 80% in 2050. Furthermore, we assumed that all gas-fired CCS consisted of NGCC-CCS technologies.

<sup>i</sup> This global discharge capacity of PHS corresponds to 13–27 TWh of storage capacity. JRC [117] estimated an available storage capacity of 54–123 TWh in Europe when a PHS consisting of two storage reservoirs cannot be more than 20 km apart from each other.

<sup>3</sup> Power system storage capacity based on Li-ion batteries is estimated to be 0.1 GW ADDIN CSL\_CITATION { "citationItems": [ { "id": "ITEM-1", "itemData": { "author": [ { "dropping-particle": "", "family": "Rastler", "given": "Dan", "non-dropping-particle": "", "parse-names": false, "suffix": "" } ], "id": "ITEM-1", "issued": { "date-parts": [ [ "2013" ] ] }, "title": "Personal communication with energy storage expert Dan Rastler of the Electric Power Research Institute (EPRI) on 03-06-2013", "type": "report", "uris": [ { "http://www.mendeley.com/documents/?uiid=3bea2338-4ab7-b562-1ef2c37f0f43" } ], "mendeley": { "previouslyFormattedCitation": "[115]", "properties": { "noteIndex": 0 }, "schema": "https://github.com/citation-style-language/schema/raw/master/csl-citation.json" } ] ] [115]. However, we also included the total worldwide capacity of Li-ion batteries for transportation application ADDIN CSL\_CITATION { "citationItems": [ { "id": "ITEM-1", "itemData": { "URL": "http://www.dailyfinance.com/2013/05/17/worldwide-capacity-of-lithium-ion-batteries-for-el/", "accessed": { "date-parts": [ [ "2013", "9", "15" ] ] }, "author": [ { "dropping-particle": "", "family": "Richard", "given": "Martin", "non-dropping-particle": "", "parse-names": false, "suffix": "" } ], "dropping-particle": "", "family": "Laverne", "given": "Murach", "non-dropping-particle": "", "parse-names": false, "suffix": "" } ], "id": "ITEM-1", "issued": { "date-parts": [ [ "2013" ] ] }, "title": "Worldwide Capacity of Lithium Ion Batteries for Electric Vehicles Will Multiply More than 10-Fold, Forecasts Navigant Research", "type": "webpage", "uris": [ { "http://www.mendeley.com/documents/?uiid=bbcb1fa1-bd88-44e1-8625-33c4e761e8ff" } ], "mendeley": { "previouslyFormattedCitation": "[116]", "properties": { "noteIndex": 0 }, "schema": "https://github.com/citation-style-language/schema/raw/master/csl-citation.json" } ] ] [116].

<sup>k</sup> According to Rubin et al. [55], technological learning does not start before a certain pre-learning phase. They argue that costs during early commercialisation of energy technologies may actually increase rather than decrease, due to uncertainties and optimism about cost data [54]. The length of the pre-learning phase is determined by the complexity and maturity of the technology. We assumed a pre-learning phase of 1 GWh for ZEBRA and Zn-Br power storage systems (with a kWh/kW ratio of 5, this is equivalent to 0.2 GW).

modelled with no more than 50% from IRES electricity generation as most investigated global mitigation scenarios have less than 50% IRES in the power generation mix.<sup>15</sup> As can be seen, the resulting capacity factors of the systems with only NGCC or NGCC+CCS are lower than their maximum availability to account for the

yearly demand pattern including the peak demand, and extra reserve above the peak demand to meet contingencies in the system. Furthermore, in the MARKAL runs, capacity credits for offshore wind and PV were, respectively, 0.15 and 0.05.<sup>16</sup> As a

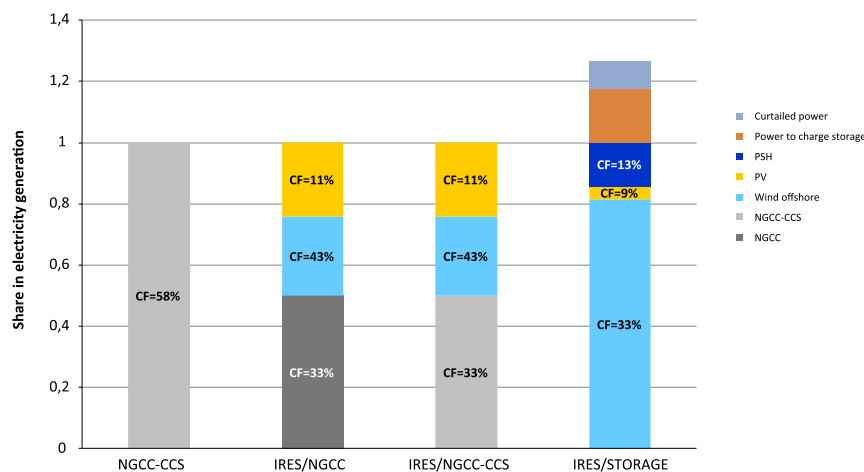
<sup>15</sup> Only in the Ecofys/WNF scenario, this rate increases to 55% in 2050 [2].

<sup>16</sup> It is not certain whether IRES can provide full power output at peak demand, therefore, it does not receive full capacity credit toward the reserves.

**Table 13**

Prices used in the calculations of LCOEs over time based on WEO 2012 2DS scenario and current policy scenario [78].

Scenario	Price of		2011	2015	2020	2025	2030	2035	2040	2045	2050
WEO2012 450	Natural gas	€/GJ	6.7	7.6	7.5	7.3	7.0	6.7	6.5	6.2	6.0
WEO2012 450	CO <sub>2</sub> emission allowance	€/tCO <sub>2</sub>	13.5	23.3	33.2	51.6	70.1	88.5	106.9	125.4	143.8
WEO2012 Current policy	Natural gas	€/GJ	6.7	7.8	8.5	9.0	9.4	9.6	9.8	10.1	10.4

**Fig. 3.** Share of technologies in electricity generation mix for the four stylized electricity generation systems.

consequence, capacity factors of the NGCC options decrease from 58% to 33%.

The capacity factors of the IRES/STORAGE system are taken from Ehler [20]. In this system, PHS takes care of the daily and weekly electricity storage requirements. Seasonal backup is realised by installing so much PV and wind capacity that in seasons with less wind or PV still sufficient electricity to cover the demand on a daily/weekly basis. As a consequence, in periods with a lot of wind or solar insolation and filled PHS reservoirs, the electricity produced by the PV modules or wind turbines is curtailed. The capacity factors of PV and offshore wind are 11% and 43% in the German system. However, part of the generated electricity is used for storage input (18% of total electricity demand), and part is curtailed (9% of total demand). Therefore, the capacity factors of wind and PV are lower in Fig. 3: they represent the electricity produced that is directly used to meet the electricity demand.

## 4. Results

### 4.1. LCOE for individual technologies

In 2011, the LCOEs of the power generation technologies vary considerably (see Fig. 4). As can be expected, NGCC plants show lower LCOE (63 €/MWh) than NGCC-CCS plants (83 €/MWh), offshore wind (167 €/MWh<sub>int</sub>), PV (231 €/MWh<sub>int</sub>), and CSP (169 €/MWh<sub>int</sub>). Electricity production costs for the PV, CSP and offshore wind systems consist mainly of capital expenditures. The remaining part is mainly made up of fixed O&M cost and extra transmission and balancing costs. NGCC-based technologies, however, have relatively low capital cost per MWh produced, but relatively high fuel costs. Also, large differences are observed in the LCOEs of the backup technologies, namely, battery systems, PHS, CAES, and NGCC-CCS. The LCOEs of the battery systems are between 1.3 and 8.9 times more expensive than the alternatives.

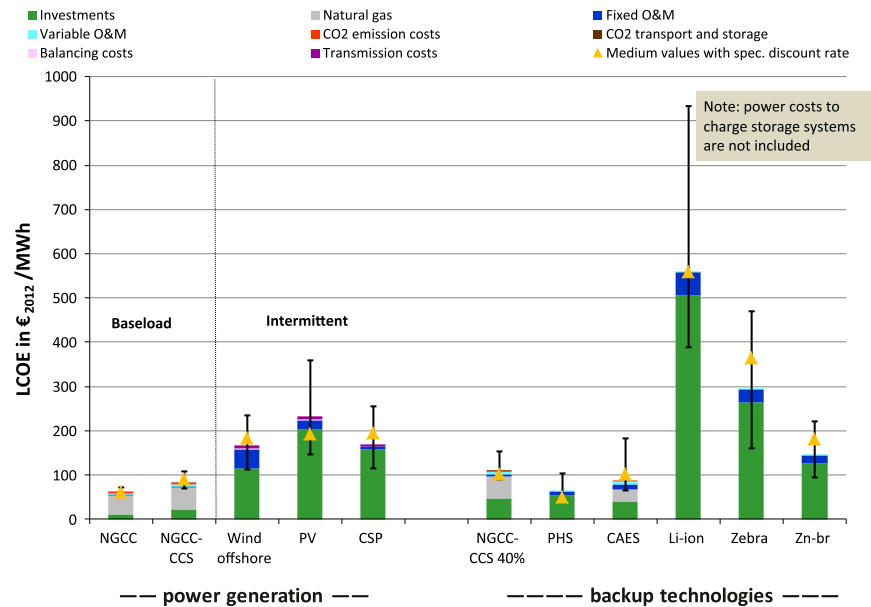
Fig. 4 also presents the variability in LCOEs for the historical year 2011. The ranges in costs for commercial technologies are due to different geographic circumstances, different plant

configurations, and different operating conditions or site-specific costs. For example, the capacity factor of PVs varies over Europe, and CSP systems can be equipped with more or less heat storage. In the case of NGCC-CCS, the cost parameters are based on estimates because a commercial scale NGCC-CCS has not yet been built. It is noteworthy that the range in LCOE for NGCC-CCS is still much smaller than those of IRES and the storage technologies.

Note that the LCOEs based on technology-specific discount rates differ from those under the base case discount rate of 10%. For NGCC-CCS (15%) and offshore wind (12%) the LCOE is higher using the technology-specific discount rate. For NGCC (8%) and PV (8%) the LCOE is lower. For CSP (10%) the LCOE remains the same.

### 4.2. LCOEs as function of cumulative capacity

Fig. 5 presents the LCOE cost projections for the maximum deployment potential of the technologies. This combines the extrapolated experience curves for investment costs (as described in the previous section) with experience curves for O&M costs (if applicable). Constant prices are assumed for natural gas (6.7 €/GJ based on the 2011 value for European gas imports in WEO2012 [78]) and CO<sub>2</sub> emissions tax (13.5 €/t based on the average EU-ETS value for 2011 [79]). The base case values for the techno-economic data and PRs were used. Besides the LCOE of baseload NGCC-CCS (with CF=87%), also that of load-following NGCC-CCS (with CF=40%) is shown in Fig. 5a. This latter technology has a similar CF as offshore wind (40%) and CSP (41%), but is fully controllable. Fig. 5b shows the LCOE of individual power storage technologies and load-following NGCC-CCS as an alternative technology for backup capacity. The power costs to charge the storage systems were excluded in the stand-alone LCOEs as these are highly uncertain. For example, if additional IRES is constructed to fill power storage systems, those costs may be high; but in cases of power oversupply those costs could be negative. In the base case, the power needed to charge the different storage systems varies between 111% (for Li-ion system) to 153% (ZnBr system) of power output.



**Fig. 4.** Breakdown of the LCOE for individual power generation and power storage technologies for the year 2011. The bars denote the LCOEs under base case conditions (a discount rate of 10%, gas price of 6.7 €/GJ, and CO<sub>2</sub> price of 13.5 €/t). The lower and upper ends of the error bars show the LCOEs under optimistic and pessimistic conditions, respectively. The yellow triangles indicate the LCOEs under base case conditions and with technology-specific discount rates. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

All power generation technologies have the potential to reduce costs to a range varying between 55 and 70 €/MWh in 2050 (see Fig. 6): PV would be at the high end of the range (67 €/MWh<sub>int</sub>), followed by NGCC-CCS (62 €/MWh), offshore wind (61 €/MWh<sub>int</sub>), CSP (55 €/MWh<sub>int</sub>) and NGCC (55 €/MWh). The IRES show larger potentials (> 60%) for cost reductions than the NGCC-based technologies (< 30%). The potential for cost reductions is largest for PV, especially due to the low PR of 80% for capital costs. Offshore wind and CSP have a higher number of doublings of capacity than PV (10 and 11, vs. 7, respectively). However, their cost reductions are slightly lower due to higher PRs for capital costs. The cost reduction potential for NGCC and NGCC-CCS plants is significantly less than for the IRES, because of the low number of doublings (i.e., 3) in the cumulative installed CC capacity, together with relatively high PRs, and the fact that the LCOEs of these technologies are mainly determined by the fuel costs. However, fuel costs also declined due to improvements (learning) in plant efficiency, which increased from 56% to 62% for NGCC, and from 48% to 57% for NGCC-CCS.

With respect to the backup systems, the battery systems have higher cost reduction potentials (> 50%) than load-following NGCC-CCS, PHS, and CAES (< 30%). The potential for *absolute* cost reductions of PHS, CAES, NGCC and NGCC-CCS are rather limited due to the fact that the costs are already relatively low (< 100 €/MWh) (NGCC and PHS). In addition, due to the large existing capacity of the CC component in the NGCC-based options (i.e. 674 GW in 2011) and the large existing PHS capacity (i.e. 127 GW in 2010), the number of doublings is smaller for these technologies than for the others.

#### 4.3. LCOE per technology as function of time

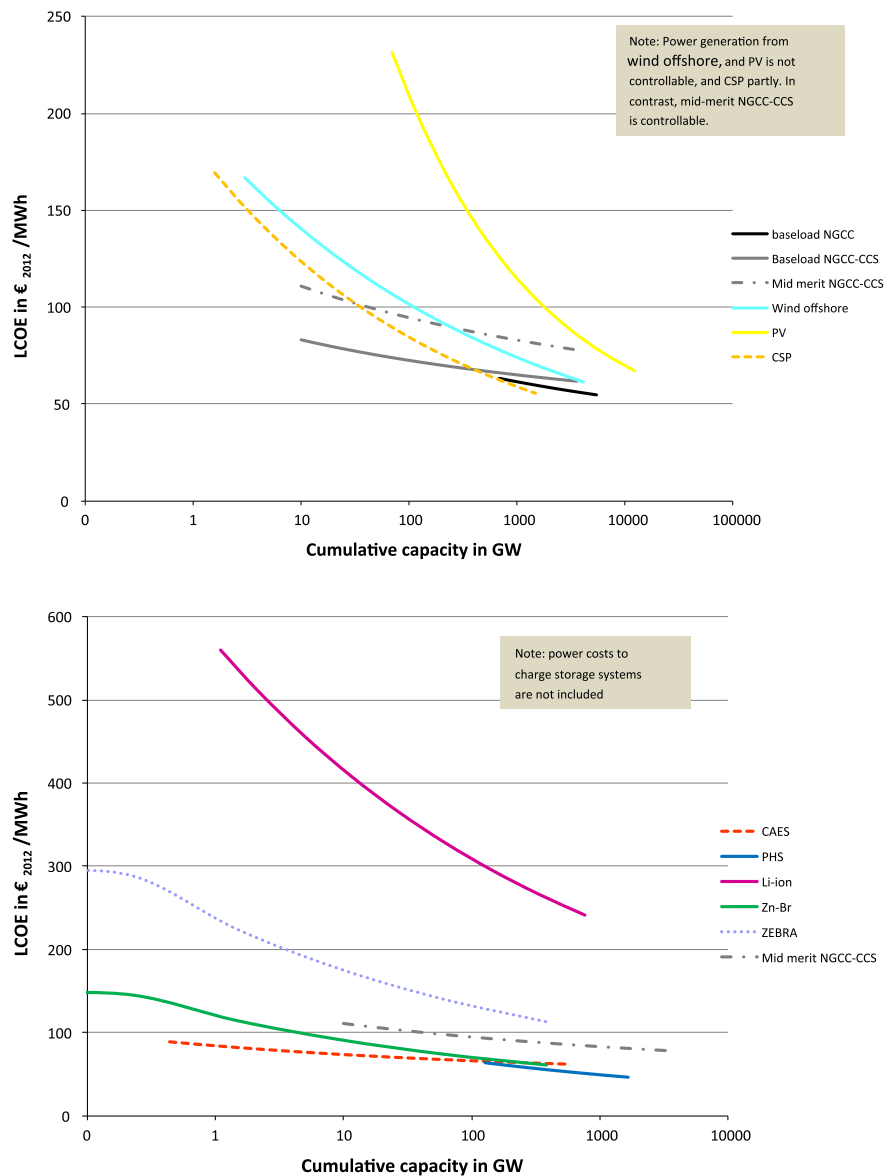
Fig. 7 presents the cost projections of the power generation technologies over time for the BASE 450, HIGH-REN and HIGH-NGCC-CCS scenarios. The projections for natural gas and CO<sub>2</sub> prices over the period 2011–2050 were taken from the World Energy Outlook 2012–450 ppm(v) scenario 2DS (see Section 4.4). The LCOEs are presented over the time frame 2011–2050.

In the HIGH-REN scenario, a rapid decline in the LCOE of PV is observed for the period 2011–2050, mainly due to the low PR of PV and approximately 7 doublings of cumulative capacity. The resulting LCOE is 67 €/MWh<sub>int</sub> in 2050. Also, offshore wind and CSP show marked cost reductions over the period 2011–2050 (offshore wind: 167 to 61 €/MWh<sub>int</sub> over 9.6 doublings; CSP: 169 to 55 €/MWh<sub>int</sub> over 10.6 doublings). The improved performance of both PV and CSP comes mainly from lower capital costs due to technological learning. For offshore wind, technological learning in O&M also reduces the cost. In spite of technological learning, the LCOE of NGCC in this scenario increases from 63 €/MWh in 2011 to 98 €/MWh in 2050 due to continuously rising CO<sub>2</sub> prices. With increasing CO<sub>2</sub> prices (unlike in Fig. 5), the LCOE of CSP and offshore wind equal the LCOE of NGCC and NGCC-CCS just after 2025, and of PV just after 2035. The LCOE of NGCC-CCS decreases from 83 €/MWh in 2011 to 69 €/MWh in 2050, which is then almost equal to the LCOE of PV. The cost decrease is due to learning in the CC (1.5 doublings) and CO<sub>2</sub> capture components (6.6 doublings). A cross-over between the LCOE of NGCC and NGCC-CCS can be observed in 2025 as a consequence of the CO<sub>2</sub> emission costs (18 €/MWh at a CO<sub>2</sub> price of 52 €/t) and the increase in cumulative capacity of CCS units (5 doublings by 2025 in this scenario, including capture units at PC as well as NGCC plants).

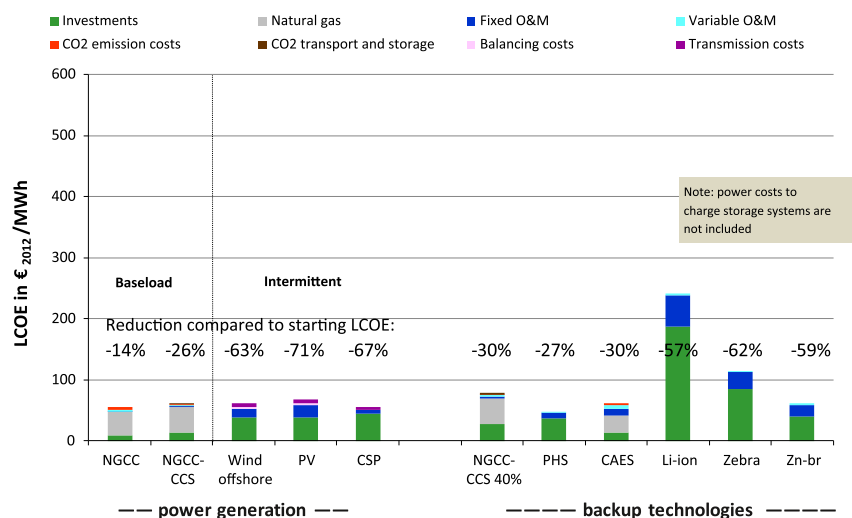
In the HIGH-NGCC-CCS scenario, the LCOEs of NGCC and NGCC-CCS stay below those of PV and CSP over the whole 2011–2050 time frame. However, the LCOE of PV is still reduced by 45% (despite the low number of doublings, i.e. 2.7) over this period compared to a smaller cost reduction of 25% for NGCC-CCS. CSP does not show cost reductions after 2011 because CSP was not considered as an option in the HIGH-NGCC-CCS scenario.

Offshore wind displays the lowest LCOE of the IRES over the period 2011–2050, and equals the LCOE of NGCC just after 2035 when it has reached 6.2 doublings. In 2050, the LCOE of offshore wind (75 €/MWh<sub>int</sub>) is still higher than that of NGCC-CCS (63 €/MWh, after 8.7 doublings of the capture unit and 3.0 doublings of the CC-component). Thus, the cost reductions for NGCC-CCS stem mainly from technological learning in the post-combustion capture unit, and to a lesser degree due to learning in the NGCC plant. For example, the investment costs of the CC-component

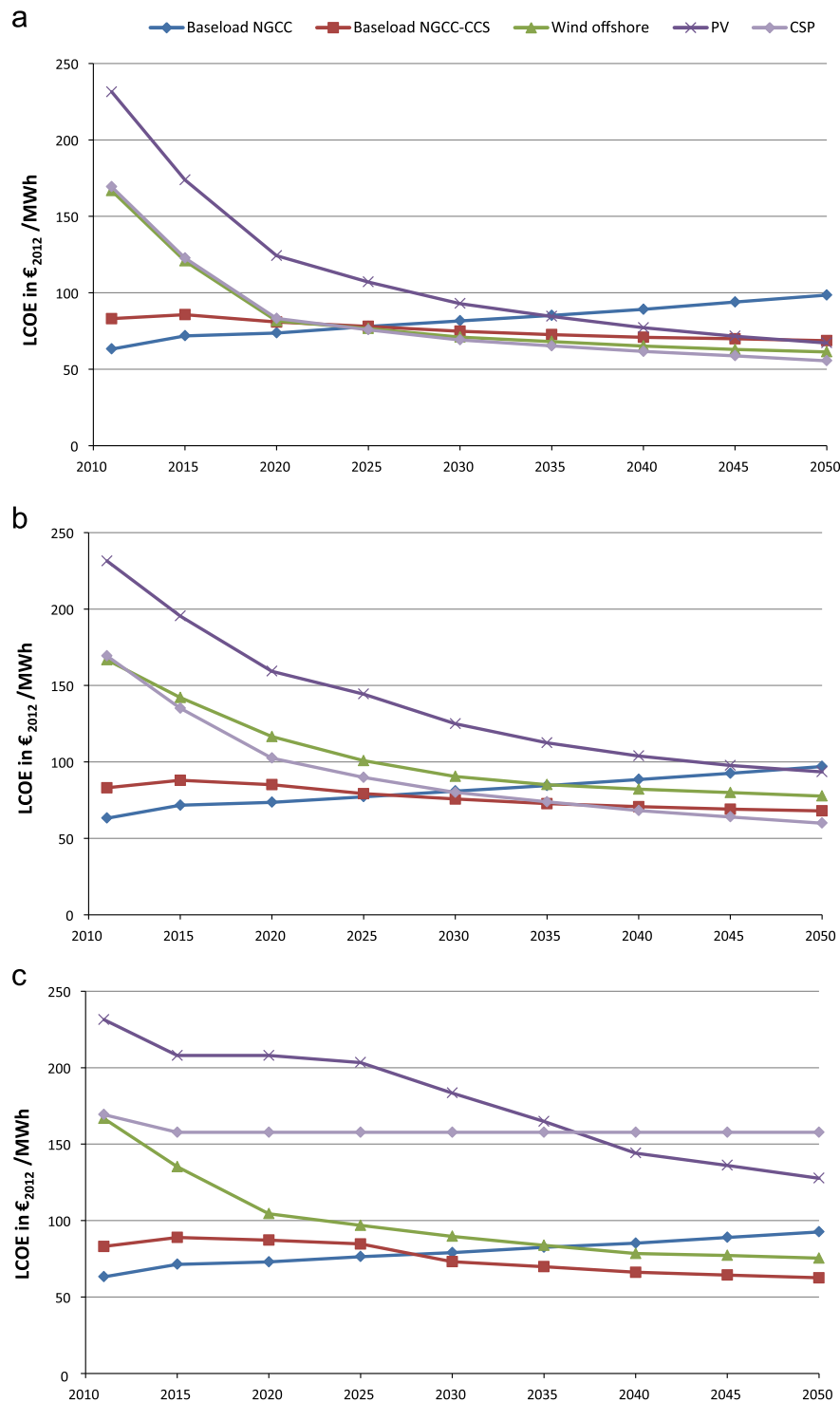




**Fig. 5.** LCOE of technologies as a function of their cumulative installed capacity under base case conditions (a discount rate of 10%, gas price of 6.7 €/GJ, and CO<sub>2</sub> price of 13.5 €/t). The left end of each line represents cumulative capacity and LCOE in the base year. The right end of each line represent the maximum capacity deployment potential in 2050, as indicated in the scenarios with minimum achievable LCOE for each technology. Upper (a): power generation technologies. Lower (b): power storage technologies and load-following NGCC-CCS as an alternative for power storage.



**Fig. 6.** Breakdown of LCOEs when maximum cumulative deployment is reached in 2050. The bars denote the LCOEs under base case conditions, a discount rate of 10%, gas price of 6.7 €/GJ, and CO<sub>2</sub> price of 13.5 €/t. The percentages in the figure present the cost reductions compared to the starting LCOEs.



**Fig. 7.** LCOEs of power generation technologies for the *HIGH-REN* (a), *BASE 450* (b), and *HIGH-NGCC-CCS*, and (c) scenarios over the period 2011–2050 under base case conditions. Note, power generation from offshore wind and PV are not controllable; CSP is partly controllable.

decreased from 856 to 625 €/kW, while the costs of the capture part of the power plant (the capture and compression units) decreased from 626 to 244 €/kW. The efficiency of the NGCC-CCS plant also increases from 48% to 57% by 2050 due to learning.

#### 4.3.1. Timing of cross-overs of LCOEs of technologies

Table 14 shows that the crossovers between the power generation technologies differ by scenario and by case (where cases

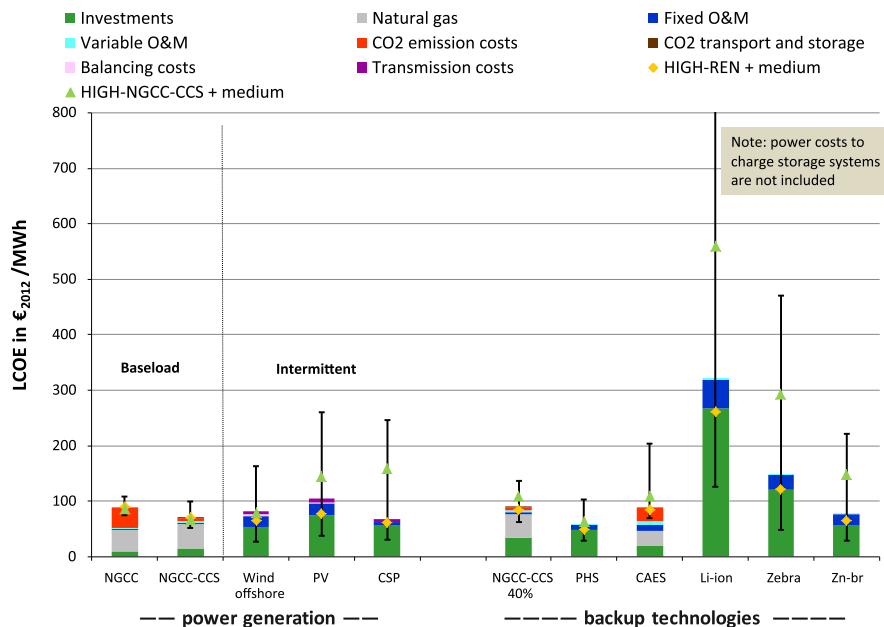
are differentiated by whether optimistic, pessimistic, or base case values are used).

With respect to the competition between NGCC and NGCC-CCS, it can be seen that in all cases NGCC-CCS has a lower LCOE than NGCC by 2050. The crossover in LCOE occurs between 2020 and 2040. Under the given CO<sub>2</sub> price development path (i.e. from 13.5 €/t to 144 €/t in 2050, see Table 13), the exact timing of the crossover depends on whether the techno-economic conditions of the capture unit are favourable compared to those of the combined cycle (CC) component.

**Table 14**

Overview of LCOE crossovers between different power generation technologies.

	Type of values <sup>a</sup>		Timing of crossover <sup>b</sup> from			
	NGCC–CCS	Alternative technology	NGCC to NGCC–CCS <sup>c</sup>	NGCC–CCS to offshore	NGCC–CCS to PV	NGCC–CCS to CSP
<i>BASE 450</i>	Opt.	Pes.	2020–2025	x	x	x
	Med.	Med.	2025–2030	x	x	2034–2040
	Pes.	Opt.	2035–2040	2011–2015	2015–2020	2011–2015
<i>HIGH–REN</i>	Opt.	Pes.	2020–2025	x	x	x
	Med.	Med.	2025–2030	2020–2025	2045–2050	2020–2025
	Pes.	Opt.	2035–2040	2011–2015	2011–2015	2011–2015
<i>HIGH–NGCC–CCS</i>	Opt.	Pes.	2025–2030 <sup>d</sup>	x	x	x
	Med.	Med.	2025–2030	x	x	x
	Pes.	Opt.	2035–2040	2011–2015	2035–2040	2011–2015

<sup>a</sup> Pes.: pessimistic; opt.: optimistic; and med: base case.<sup>b</sup> The period when the technology with the lowest LCOE in 2011 becomes more expensive than the alternative.<sup>c</sup> In the assessment of the LCOE crossovers between NGCC and NGCC–CCS, the type of values (pes., opt., med.) refer to the values of the capture unit of the NGCC–CCS and the CC-component in the case of NGCC.<sup>d</sup> Although this is the *HIGH–NGCC–CCS* scenario implying that the cumulative capacity of NGCC–CCS is highest in 2050 in this scenario, the deployment of NGCC–CCS starts later in this scenario than in the other scenarios (see Fig. 2) and, therefore, the crossover is 5 years later.**Fig. 8.** Sensitivity analysis for LCOEs of technologies in 2040.**Table 15**

Variants used for the sensitivity analysis.

Scenario/type of values	Base case	Optimistic	Pessimistic
<i>BASE 450</i>	X	X	X
<i>BASE 450 + high gas price scenario<sup>a</sup></i>	X		
<i>HIGH–REN</i>	X	X	X
<i>HIGH–NGCC–CCS</i>	X	X	X

<sup>a</sup> Gas price development is based on the Current policy scenario in WEO 2012 [78].

Table 14 also gives insights into the development of competition between NGCC–CCS and the IRES technologies. An LCOE crossover from NGCC–CCS to IRES never occurs in cases with pessimistic estimates for IRES and optimistic estimates for NGCC–CCS. However, LCOE crossovers from NGCC–CCS to IRES take place for the base case assumptions in the *HIGH–REN* scenario, to some extent in *BASE 450*, and not at all in *HIGH–NGCC–CCS*. The crossovers in cases with optimistic estimates for IRES occur mostly

before 2015, meaning that IRES under favourable conditions already have lower LCOEs than NGCC–CCS with costs at the high end of the range. Summarizing, the cost-effectiveness of IRES in relation to NGCC–CCS is very dependent on the specific conditions of where and how IRES is applied and the relative costs of different technologies.

#### 4.3.2. Sensitivity analysis

Fig. 8 shows the sensitivity of the LCOE for power generation and power storage technologies for the illustrative year 2040 based on ten variants (see Table 15). All variants were calculated using natural gas prices from the WEO450 scenario (except for one instance) and a discount rate of 10%. The levelised cost of electricity (LCOE) in 2040 was assessed to be 71 €/MWh for baseload NGCC–CCS plants (with CF of 87%), and 68, 82, and 104 €/MWh<sub>int</sub> for, respectively, concentrated solar power (CSP with thermal storage and CF of 41%), offshore wind plants (with CF of 40%), and PV (with CF of 14%).

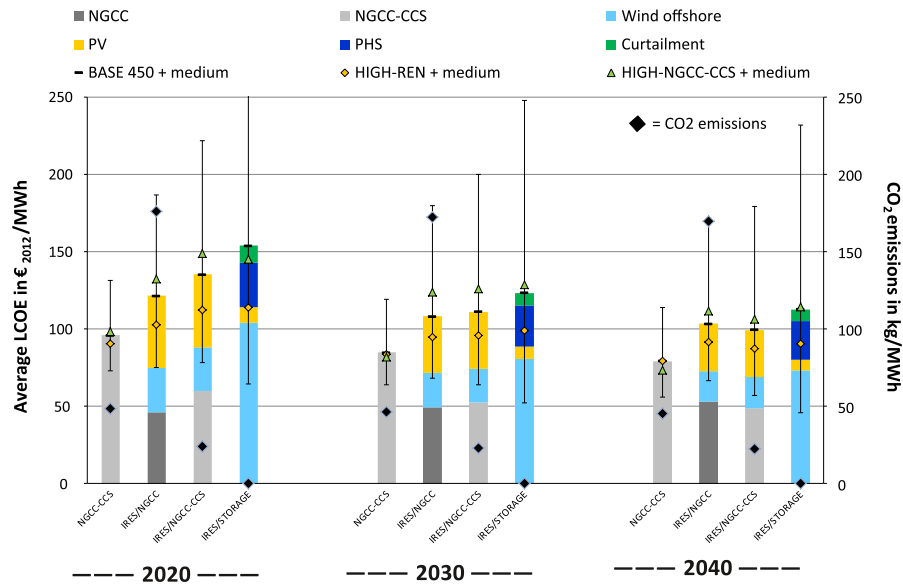


Fig. 9. Annual average LCOE of the four stylized electricity generation systems and the contribution of different technologies to the cost.

**4.3.2.1. Power generation technologies.** The large variations in the LCOE of IRES options shown in Fig. 8 are not merely due to techno-economic uncertainties and ranges in PRs, but also to differences in technology configurations (e.g. CPS with more or less storage) and geographical conditions. The LCOE ranges of most technologies apply to the whole of Europe except for the LCOE of CSP which applies only to South Europe. Less favourable conditions in Northern Europe were not accounted for in the input data for CSP technologies.

Different techno-economic assumptions and scenarios have a smaller impact on the LCOEs of NGCC and NGCC-CCS than for IRES technologies. While the LCOE of NGCC-CCS varies between  $-27\%$  and  $+41\%$  of the base case value in 2040, the LCOEs of the IRES vary between  $-68\%$  and  $+260\%$ .

If we compare the LCOE ranges of the IRES technologies to each other, the range is largest for CSP ( $-57\%$  to  $+260\%$ ), followed by PV ( $-64\%$  to  $+150\%$ ) and offshore wind ( $-68\%$  to  $+97\%$ ). The highest LCOE of CSP is a consequence of no deployment of CSP resulting in no learning, a system with no heat storage, a low availability factor, and pessimistic cost data.

The *HIGH-REN* and *HIGH-NGCC-CCS* scenarios have limited impact on the LCOEs of the NGCC-based power plants and offshore wind in 2040, because the number of cumulative doublings of these technologies does not differ much per scenario. Conversely, the choice of scenario has a large influence on the LCOE of PV and CSP. Differences in cumulative doublings for PV and CSP are 4 and 8, respectively.

Note also that the  $\text{CO}_2$  price can have a significant impact on the LCOE of NGCC and thus on its competitiveness. The red part of the bar representing the  $\text{CO}_2$  emission costs would double with a doubling of the  $\text{CO}_2$  emission allowance price.

Summarizing, the base case LCOE values for 2040 are lowest for NGCC-CCS, followed by CSP, offshore wind, NGCC, and PV. However, the large variation in LCOEs for the IRES could result in much lower or higher LCOEs, depending on techno-economic costs, PRs, deployment rate, technology configurations, and geographical conditions.

**4.3.2.2. Power storage technologies.** Fig. 8 also gives an indication of the learning potential of power storage technologies and uncertainties involved. As no data were available on deployment

rates of any of the storage technologies we assumed these rates could be zero as well. The highest LCOEs occur where no learning has taken place and pessimistic conditions still persist in 2040.

With respect to backup technologies, the LCOE of load-following NGCC-CCS (with  $\text{CF}=40\%$ ) has the smallest uncertainty range ( $-32\%$  to  $+50\%$  of the base case value). In 2040, its base case LCOE is 2–33 €/MWh higher than CAES, PHS, and Zn-Br. However, these latter values do not include power costs to charge the systems. Of the power storage technologies, PHS seems to perform the best: it is the cheapest with the lowest financial risks. The LCOE of PHS not only has the lowest LCOE (57 €/MWh) compared to the other power storage technology, but also the smallest uncertainty range (i.e. from  $-50\%$  to  $+81\%$  of its base case value). Furthermore, it is noteworthy that its highest LCOE value is just over 100 €/MWh, which is low compared to the highest cost for other storage technologies (i.e. between 204 and 933 €/MWh). The base case values of the Li-ion and ZEBRA battery systems are even higher (i.e. 321 and 149 €/MWh, respectively).

With regard to the impact of different scenarios (*HIGH-NGCC-CCS* vs. *HIGH-REN*), the power storage technologies respond differently. The choice of scenario hardly has an impact on the LCOE of PHS because the number of doublings is never more than four (due to a high initial cumulative capacity and the long lifetime of the technology). In the case of batteries, the choice of scenario has a large impact because the number of doublings varies between zero in *HIGH-NGCC-CCS* and 9 to 11 in *HIGH-REN*. This uncertainty in the future deployment of batteries makes it difficult to project their costs. Although doublings in the CAES technology vary between zero and almost ten depending on the scenario, this range does not have a major effect on the LCOE because the LCOE is determined mainly by the fuel costs and the  $\text{CO}_2$  emission costs.

#### 4.4. LCOE of total systems

Fig. 9 presents the annual average LCOEs and the  $\text{CO}_2$  emissions for each stylized system. The bars show the LCOE development in the *BASE 450* scenario for the years 2020, 2030, and 2040 under base case conditions. The error bars are based on LCOEs of all variants specified in Table 15.

In all four systems  $\text{CO}_2$  emissions are considerably below the average  $\text{CO}_2$  emission rate of 400 kg/MWh for electricity generation in the EU27 in 2009 [80]. For example, in 2040,  $\text{CO}_2$  emissions



decrease to 45 kg/MWh for the NGCC–CCS system, 23 kg/MWh for the IRES/NGCC–CCS system, and zero kg/MWh for the IRES/STORAGE system. These represent reductions below 2009 values of 89%, 94%, and 100%, respectively, for the three systems above. For the IRES/NGCC system the reduction is only 58%, the smallest of the four cases.

With regard to costs, the annual average LCOE of the system based only on natural gas (the NGCC–CCS system) remains the lowest over the whole period while achieving an 89% emission reduction. For the systems based on a combination of natural gas and IRES, the annual average LCOE of the system with CCS (IRES/NGCC–CCS) is higher in 2020 and 2030 than the system without CCS (IRES/NGCC) due to its higher capital cost and low capacity factor. In 2040, however, the higher CO<sub>2</sub> emission price of 107 €/t results in IRES/NGCC–CCS becoming cheaper than IRES/NGCC. Furthermore, the LCOE of IRES/NGCC is more sensitive to the CO<sub>2</sub> price. For example, in 2030 for each 10 €/t increase in CO<sub>2</sub> price, the LCOE of the IRES/NGCC system increases by 1.7 €/MWh, while for the IRES/NGCC–CCS system the cost increase is only 0.2 €/MWh.

Finally, the zero CO<sub>2</sub> emission system based only on IRES and energy storage is the most expensive system in all periods. The annual average LCOE of this system in 2040 is 13% more expensive than the IRES/NGCC–CCS system and 42% more expensive than the NGCC–CCS system for the base case assumptions. For other years these percentages vary. Note that the cost of the IRES/STORAGE system could be underestimated for two reasons. The first is that it is based mainly on offshore wind. If the share of PV were higher, the system LCOE would increase because the LCOE of PV is higher than offshore wind (for example, 26% higher in 2040, see Fig. 8). Secondly, if another storage technology were used instead of PHS, the overall cost would again increase since PHS is the lowest-cost storage technology—the LCOEs of other options are 55% to 462% higher (see Fig. 8). Only if some offshore wind were replaced by CSP (with a 17% lower LCOE in 2040) would the overall LCOE of the IRES/STORAGE system decrease relative to the base case values.

Note that since the four stylized systems achieve different levels of CO<sub>2</sub> reductions, their cost-effectiveness levels (€/tonne CO<sub>2</sub> avoided) are not simply proportional to the differences in LCOE. Thus, the CO<sub>2</sub> avoidance cost of the systems in a specific period compared to an NGCC reference system in the same period<sup>17</sup> is lowest for the NGCC–CCS system (decreasing from 87 €/tCO<sub>2</sub> in 2020 to 57 €/tCO<sub>2</sub> in 2040). The CO<sub>2</sub> avoidance cost of the IRES/NGCC–CCS system decreases from 147 to 124 €/tCO<sub>2</sub>, while for the highest-cost IRES/STORAGE system the avoidance cost falls from 244 to 162 €/tCO<sub>2</sub> between 2020 and 2040 (Fig. 10).

The error bars in Fig. 9 shows the spread in the annual average LCOEs due to uncertainties and variability of assumptions. In the NGCC–CCS system, the spread is the smallest (ranging from –29% to +44% compared to the base case LCOE), while the spread of IRES/STORAGE is highest, ranging from –59% to +106% of the base cases value (Table 16).

## 5. Discussion

Our assessment of the LCOE trajectories for different power generation and storage technologies required a considerable amount of input data including techno-economic data, progress ratios for different technologies, and projections of technology deployment. To deal with the associated uncertainties, all input

data and their uncertainty ranges were fully reported and documented insofar as possible based on an extensive literature review. The effects of all uncertainties also are clearly shown in the results presented, in contrast to other studies that often neglect uncertainties, e.g. [81,82]. LCOE figures reported in other prominent studies like the IEA Energy Technology Perspectives 2014 report [5] fall within the ranges found in this paper. In the remainder of this section, a few issues concerning specific limitations and uncertainties of this study are further elaborated.

- The techno-economic input data underlying the LCOEs in this study were taken from different sources in order to represent Europe as a case study region. However, it was not always possible to find sufficient data for all of Europe. For example, cost data for offshore wind were taken from studies applying to the UK as these estimates were most recent and detailed. Data on offshore wind from South European countries would be especially desirable to validate the current input data.
- Uncertainty related to the pace of technological learning was addressed by using ranges rather than single values for PRs. Reliable and robust values for PRs were not available for all technologies due either to their early stage of development (CAES, ZEBRA and ZnBr batteries), limited installed capacity (CSP and CAES), or difficulty of standardizing a complex technology (CSP, offshore wind). Furthermore, the use of equipment prices creates uncertainty in some estimates of PR, especially for PV systems and offshore wind turbines, which are susceptible to fierce market dynamics. More research also is needed on the trajectory of O&M costs for most technologies. Here, PR values were applied only to O&M costs of NGCC-based options and offshore wind systems. Finally, learning rates for CCS were derived from cost reductions observed for analogous technologies (e.g. the PR of flue gas desulphurisation systems was used for the amine-based CO<sub>2</sub> capture system). To reduce these uncertainties, future studies should attempt to identify the potential for cost reductions from a bottom-up perspective for all technologies, insofar as possible (e.g. as was done by Junginger et al. [11] for offshore wind).
- The techno-economic input data for novel technologies, such as ZEBRA and ZnBr batteries, entail large uncertainty due to their early development stage. On-going research and demonstration projects will have to prove the techno-economic feasibility of these technologies. Moreover, the cost competitiveness of Li-ion and ZEBRA batteries will depend partly on the availability (or scarcity) of key materials, mainly lithium and nickel. This is difficult to estimate given uncertainties in world reserves, undiscovered resources, supply chain constraints and demands from other sectors.
- Numerous other battery types (e.g. metal-air and flow batteries) show favourable techno-economic features in the long term and could become credible alternatives to those analyzed here. Including other battery technologies in follow-up research is therefore recommended.
- The worldwide global energy scenarios available for this study did not provide data on the required deployment of power storage technologies. Although they acknowledge the need for power storage in their scenarios, they do not quantify their use or identify which type of storage technologies would be deployed. Further research should provide insights into the potential deployment of these technologies.
- In this study, we investigated four stylized power systems in order to compare the full costs of alternative systems employing natural gas and intermittent renewables on a level playing field, including costs for adequacy as well as balancing and transmission costs. The power mixes in future scenarios in which CO<sub>2</sub> emissions are reduced drastically will certainly be more complex than these stylized systems. Furthermore, a full

<sup>17</sup> Note, that in order to evaluate whether the CO<sub>2</sub> price is high enough to cover the CO<sub>2</sub> avoidance costs, the reference system should be the business as usual system without climate policy. The NGCC reference system is probably not the business as usual system.

analysis needs to take into account future load pattern developments due to changes in electrical appliances (e.g. electric vehicles) and demand side management measures. Results from power system simulation modelling for such systems, including data on capacity factors and storage requirements, are not sufficiently available at the present time.

- To better quantify the need for power storage and the full costs of other projected mixes of low-carbon power systems, the inclusion of demand side management measures, together with more extensive and detailed power system simulation modelling of the type found elsewhere in literature (e.g. [125–128]), is recommended for future studies.

## 6. Conclusions

The objective of this paper was to obtain insights into the comparative costs, on a level playing field, of natural gas combined cycle power plants with CO<sub>2</sub> capture and storage (NGCC–CCS) versus intermittent renewable energy systems (IRES) combined with power storage technologies in a CO<sub>2</sub> mitigation portfolio. We focussed on three IRES technologies, namely, PV, offshore wind, and CSP with thermal storage, plus five power storage technologies, PHS, CAES, and Li-ion, ZEBRA, and Zn–Br battery systems.

The potential cost reduction due to technological learning up to 2050 was estimated for each technology by combining technoeconomic data, progress ratios, and deployment projections from different worldwide energy scenarios. For the intermittent renewable technologies, extra balancing and transmission costs were included (3 €/MWh<sub>int</sub> and 6 €/MWh<sub>int</sub>, respectively, in the base case). “Optimistic” and “pessimistic” cost estimates for each technology were developed to bound the base case values. For context, all energy and technology costs were based on European values, and an increasing price on CO<sub>2</sub> emissions from 2011 to 2050 was assumed as a driver for emission mitigation.

In all cases, it was found that by 2050 NGCC–CCS as a baseload technology had a lower LCOE than NGCC without CCS due mainly to the effect of the CO<sub>2</sub> price. Depending on the scenario, the cost crossover occurs between 2020 and 2040. NGCC–CCS also remains cheaper than IRES under pessimistic assumptions regarding IRES learning rates and technology costs. However, with optimistic

assumptions the cost of variable (intermittent) electricity from IRES may be lower than baseload electricity from NGCC–CCS before 2020. The uncertainty in LCOE ranges for renewables is much wider than for the NGCC cases, mainly due to higher uncertainties in technology costs, the larger number of “doublings” of installed capacity, different deployment rates across scenarios, and varying geographical conditions. The cost reduction potential for power storage technologies also showed large variations (Tables 17 and 18).

We found that in 2040 under base case assumptions backup using NGCC–CCS (40% capacity factor) with an LCOE of 90 €/2012/MWh is more costly than PHS or CAES backup with LCOEs (excluding charging cost) of 57 and 88 €/2012/MWh, respectively. Projected costs for battery backup are 78, 149, and 321 €/2012/MWh for Zn–Br, ZEBRA, and Li-ion battery systems, respectively.

We also compared the LCOEs of four stylised “island” power systems providing low-carbon electricity generation on a common basis, including additional costs for adequacy of service in cases with intermittent renewable technologies. We found that in 2040 under base case conditions a zero CO<sub>2</sub> emission system with IRES plus PHS backup was 13% more expensive in terms of LCOE than IRES plus NGCC–CCS backup with emissions of 23 kg CO<sub>2</sub>/MWh, and 42% more costly than the system employing only NGCC–CCS with CO<sub>2</sub> emissions of 45 kg/MWh. The scenario with high deployment rates of IRES showed that high deployment is essential to drive down future power system costs.

In future research, we propose to investigate the requirements and total cost of the more complex power system portfolios projected in global climate change mitigation scenarios. Specifically, more advanced power system simulation modelling (including all costs for adequacy, transmission and balancing requirements, as well as demand side management measures) is necessary to estimate power storage requirements, curtailment of renewables, and overall costs of low-carbon energy systems (Figs 11 and 12).

## Acknowledgement

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## Annex I. Overview of all techno-economic values per technologies for the base case, optimistic, and pessimistic variants

See Tables 16–18.

**Table 16**

Overview of values used in the base case variants (i.e. TCR and OPEX costs and efficiencies in the base year, additional costs, and PRs) and the specific discount rate per technology (only used in a sensitivity variant).

Technology	Reference year	TCR (k €/kW)	PR TCR (%)	Discount rate (%)	Economic lifetime (years)	FOM (€/kW/y)	VOM (€/MWh)	PR OPEX (%)	Efficiency LHV (%)	PR energy loss (%)	Availability factor (%)	Additional costs
NGCC	2011	0.79	90 <sup>a</sup>	7.5	25	9	2.7	94 <sup>a</sup>	56	95 <sup>a</sup>	87	–
NGCC (part of NGCC-CCS plant)	2011	0.86	90 <sup>a</sup>	14.5	25	10	3.2	94 <sup>a</sup>	56	95 <sup>a</sup>	87	7 €/t CO <sub>2</sub> <sup>g</sup>
CO <sub>2</sub> capture unit (90%)	2011	0.59	89 <sup>b</sup>	14.5	25	6	2.7	78 <sup>b</sup>	8% point penalty	95 <sup>b</sup>		
CO <sub>2</sub> compression unit	2011	0.04	98									
Offshore wind	2011	3.43	90 <sup>a</sup>	12	20	151	0	90 <sup>e</sup>		–	40	9 €/MWh <sup>i</sup>
PV	2012	2.00	80 <sup>a</sup>	7.5	25	25	0	100 <sup>f</sup>		–	14	9 €/MWh <sup>i</sup>
CSP (SM2, 6–9 h storage)	2010	6.65	88 <sup>a</sup>	12	25	34	0	100 <sup>f</sup>		–	41	5.5 €/MWh <sup>i</sup>
									Round trip efficiency/NG efficiency		Cycli per year, ratio kWh <sub>stor</sub> /kW	
PHS	2010	1.77	90 <sup>d</sup>	7.5	60	30	0.6	100 <sup>f</sup>	80	100 <sup>f</sup>	365, 9	–
CAES	2011	1.01	90 <sup>d</sup>	14.5	20	31	6.7	100 <sup>f</sup>	80/87	100 <sup>f</sup>	365, 8	–
		(€/kWh <sub>stor</sub> )				(€/kWh <sub>stor</sub> /y)						
Li-ion	2010	1.41	90 <sup>c,d</sup>	10	15	19	2.6	100 <sup>f</sup>	90	100 <sup>f</sup>	365, 4	–
ZEBRA	2011	0.74	90 <sup>d</sup>	14.5	15	10	0.9	100 <sup>f</sup>	90	100 <sup>f</sup>	365, 5	–
ZnBr	2011	0.35	90 <sup>d</sup>	14.5	15	7	2.5	100 <sup>f</sup>	65	100 <sup>f</sup>	365, 5	–

<sup>a</sup> Based on historical data of the technology.

<sup>b</sup> Based on historical data of an analogous technology.

<sup>c</sup> Although a PR of 83% was identified for the Lithium-ion battery, no PR was identified for a storage system based on Lithium-ion batteries.

<sup>d</sup> A PR of 90% was chosen as in the ReMIND model (Luderer et al. [68]). However, this does not seem to be based on historical data.

<sup>e</sup> The same PR as for the TCR is applied assuming there is a fixed ratio between TCR and OPEX.

<sup>f</sup> No quantitative data on the learning potential were found. We assumed no learning in these cases.

<sup>g</sup> Costs for CO<sub>2</sub> transport and storage.

<sup>i</sup> Costs for extra balancing and transmission associated with IRES. In the case of CSP, only extra transmission costs are considered.

**Table 17**

Overview of values used in the optimistic variants (i.e. TCR and OPEX costs and efficiencies in the base year, additional costs, and PRs).

Technology	Reference year	TCR (k €/kW)	PR TCR (%)	Economic lifetime (years)	FOM (€/kW/y)	VOM (€/MWh)	PR OPEX (%)	efficiency LHV (%)	PR energy loss (%)	Availability factor (%)	Additional costs
NGCC	2011	0.59	85	30	6	1.9	90	58	92	93	–
NGCC (part of NGCC-CCS plant)	2011	0.62	85	30	7	2.2	90	58	92	93	3 €/t CO <sub>2</sub> <sup>g</sup>
CO <sub>2</sub> capture unit (90%)	2011	0.40	83	30	5	1.9	70	8% point penalty	92		
CO <sub>2</sub> compression unit	2011	0.03	95								
Offshore wind	2011	2.15	86	25	97	0	86 <sup>e</sup>		–	34	1 €/MWh <sup>i</sup>
PV	2012	1.80	75	30	27	0	100 <sup>f</sup>		–	20	1 €/MWh <sup>i</sup>
CSP (SM2, 13–15 h storage)	2010	6.41	85	30	12	0	100 <sup>f</sup>		–	61	1 €/MWh <sup>i</sup>
										Cycli per year, ratio kWh <sub>stor</sub> /kW	
PHS	2010	2.10	85	70	34	0.6	100 <sup>f</sup>	85	100 <sup>f</sup>	365, 16	–
CAES	2011	0.55	85	25	25	6.7	100 <sup>f</sup>	90/91	100 <sup>f</sup>	365, 8	–
		(€/kWh <sub>stor</sub> )			(€/kWh <sub>stor</sub> /y)						
Li-ion	2010	1.09	85	20	13	2.0	100 <sup>f</sup>	95	100 <sup>f</sup>	365, 5	–
ZEBRA	2011	0.44	85	20	7	0.9	100 <sup>f</sup>	90	100 <sup>f</sup>	365, 5	–
ZnBr	2011	0.25	85	20	4	1.1	100 <sup>f</sup>	70	100 <sup>f</sup>	365, 5	–

<sup>e</sup> The same PR as for the TCR is applied assuming there is a fixed ratio between TCR and OPEX.

<sup>f</sup> No quantitative data on the learning potential were found. We assumed no learning in these cases.

<sup>g</sup> Costs for CO<sub>2</sub> transport and storage.

<sup>i</sup> Costs for extra balancing and transmission associated with IRES.

**Table 18**

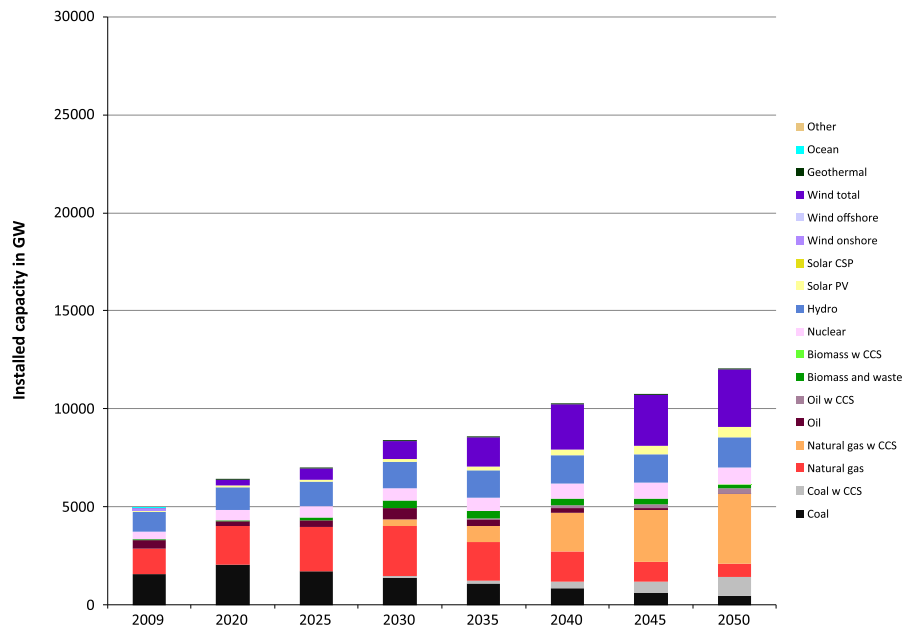
Overview of values used in the pessimistic variants (i.e. TCR and OPEX costs and efficiencies in the base year, additional costs, and PRs).

Technology	Reference year	TCR (k €/kW)	PR TCR (%)	Economic lifetime (years)	FOM (€/kW/y)	VOM (€/MWh)	PR OPEX (%)	Efficiency LHV (%)	PR energy loss (%)	Availability factor (%)	Additional costs
NGCC	2011	0.95	95	20	11	3.6	100	54	98	80	–
NGCC (part of NGCC–CCS plant)	2011	1.22	95	20	13	4.2	100	54	98	80	11 €/t CO <sub>2</sub> <sup>g</sup>
CO <sub>2</sub> capture unit (90%)	2011	1.14	94	20	8	3.5	90	8% point penalty	98		
CO <sub>2</sub> compression unit	2011	0.07	100								
Offshore wind	2011	4.22	94	15	264	0	94 <sup>e</sup>		–	46	32 €/MWh <sup>i</sup>
PV	2012	2.40	85	20	30	0	100 <sup>f</sup>		–	12	32 €/MWh <sup>i</sup>
CSP (SM2, 0 h storage)	2010	5.24	92	30	71	0	100 <sup>f</sup>		–	19	32 €/MWh <sup>i</sup>
								Round trip efficiency/natural gas		Cycli per year, ratio kWh <sub>stor</sub> /kW	
PHS	2010	2.58	95	50	40	0.6	100 <sup>f</sup>	75	100 <sup>f</sup>	365, 8	–
CAES	2011	1.70	95	15	34	8.6	100 <sup>f</sup>	70/83	100 <sup>f</sup>	365, 5	–
		(€/kWh <sub>stor</sub> )			(€/kWh <sub>stor</sub> /y)						
Li-ion	2010	1.95	95	10	22	3.3	100 <sup>f</sup>	85	100 <sup>f</sup>	365, 3	–
ZEBRA	2011	0.96	95	10	14	2.0	100 <sup>f</sup>	90	100 <sup>f</sup>	365, 5	–
ZnBr	2011	0.43	95	10	9	2.5	100 <sup>f</sup>	60	100 <sup>f</sup>	365, 5	–

<sup>e</sup> The same PR as for the TCR is applied assuming there is a fixed ratio between TCR and OPEX.<sup>f</sup> No quantitative data on the learning potential were found. We assumed no learning in these cases.<sup>g</sup> Costs for CO<sub>2</sub> transport and storage.<sup>i</sup> Costs for extra balancing and transmission associated with IRES.

## Annex II. Deployment of power generation technologies for the three studied scenarios

See Figs. 10–12

**Fig. 10.** Installed capacity of the HIGH-NGCC-CCS scenario. Data based on the IMAGE-mix pathway in GEA [4].



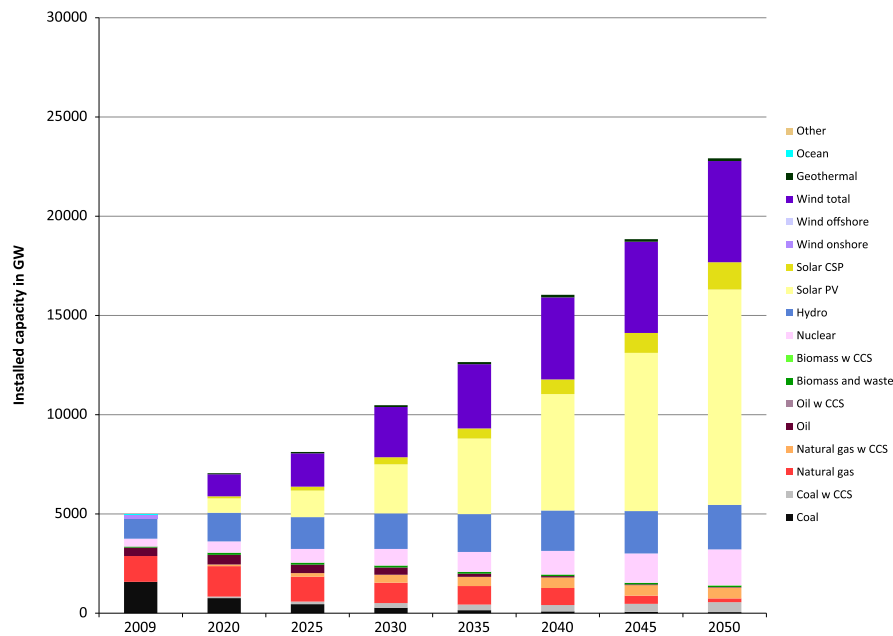


Fig. 11. Installed capacity of HIGH-REN scenario. Data based on the GEA-efficiency–conventional transport–no beccs, no sinks, limited biomass pathway in GEA [4].

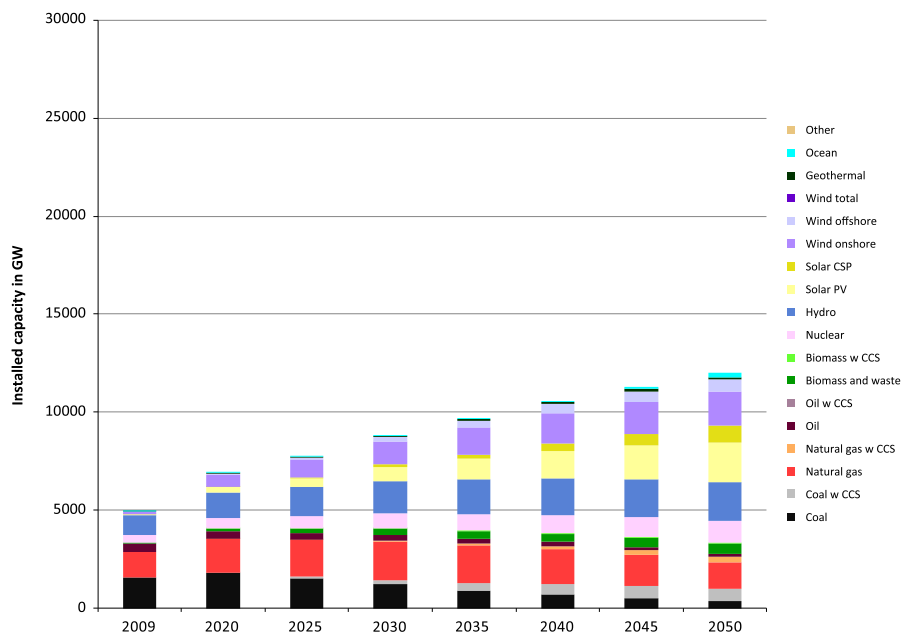


Fig. 12. Installed capacity of BASE 450 scenario. Data taken from ETP 2012 [76]. Hydropower does not include pumped hydro storage capacity.

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