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Least-cost options for integrating intermittent renewables in low-carbon power systems

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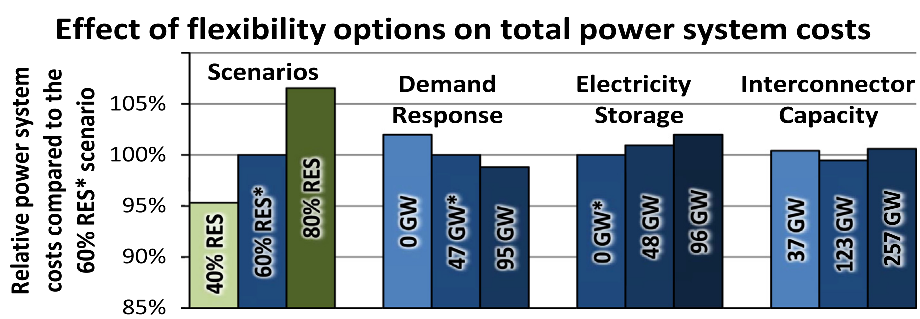
HIGHLIGHTS

- Simulated the 2050 West-European power system with 40%, 60% and 80% RES penetration.
- Assessed if 5 options can complement intermittent RES and lower total system costs.
- 3 options lower costs: demand response, gas-fired generators(+CCS) and curtailment.
- Power storage is too expensive and extra interconnectors are valuable at RES ⩾60%.
- Virtually all generators encounter a revenue gap in the current energy-only market.

GRAPHICAL ABSTRACT



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ABSTRACT

Large power sector CO_2 emission reductions are needed to meet long-term climate change targets. Intermittent renewable energy sources (intermittent-RES) such as wind and solar PV can be a key component of the resulting low-carbon power systems. Their intermittency will require more flexibility from the rest of the power system to maintain system stability. In this study, the efficacy of five complementary options to integrate intermittent-RES at the lowest cost is evaluated with the PLEXOS hourly power system simulation tool for Western Europe in the year 2050. Three scenarios to reduce CO_2 emissions by 96% and maintain system reliability are investigated: 40%, 60% and 80% of annual power generation by RES. This corresponds to 22%, 41% and 59% of annual power generation by intermittent-RES. This study shows that higher penetration of RES will increase the total system costs: they increase by 12% between the 40% and 80% RES scenarios. Key drivers are the relatively high investment costs and integration costs of intermittent-RES. It is found that total system costs can be reduced by: (1) Demand response (DR) (2–3% reduction compared to no DR deployment); (2) natural gas-fired power plants with and without Carbon Capture and Storage (CCS) (12% reduction from mainly replacing RES power generation between the 80% and 40% RES scenarios); (3) increased interconnection capacity (0–1% reduction compared to the current capacity); (4) curtailment (2% reduction in 80% RES scenario compared to no curtailment); (5)

Abbreviations: CAES, Compressed Air Energy Storage; CCS, Carbon Capture and Storage; CHP, Combined Heat and Power; DR, Demand Response; ECF, European Climate Foundation; ETP'14, Energy Technology Perspectives 2014; FOM, Fixed Operation and Maintenance; GT, Gas Turbine; iRES, Intermittent Renewable Energy Sources; LCOE, Levelized Cost of Electricity; Li-ion, Lithium Ion Battery; LWA, Load Weighted Average; MAE, Mean Absolute Error; MIP, Mixed Integer Programming; NaS, Sodium Sulfur Battery; NGCC, Natural Gas Combined Cycle; NGCC-CCS, Natural Gas Combined Cycle with CCS; PHS, Pumped Hydro Storage; PC, Pulverized Coal; PC-CCS, Pulverized Coal with CCS; RES, Renewable Energy Source; TCR, Total Capital Requirement; TOC, Total Overnight Costs; UCED, Unit Commitment and Economic Dispatch; VOM, Variable Operation and Maintenance; VRB, Vanadium Redox Battery.

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electricity storage increases total system costs in all scenarios (0.1–3% increase compared to only current storage capacity). The charging costs and investment costs make storage relatively expensive, even projecting cost reductions of 40% for Compressed Air Energy Storage (CAES) and 70% for batteries compared to 2012. All scenarios are simulated as energy only markets, and experience a "revenue gap" for both complementary options and other power generators: only curtailment and DR are profitable due to their low cost. The revenue gap becomes progressively more pronounced in the 60% and 80% RES scenarios, as the low marginal costs of RES reduce electricity prices.

1. Introduction

Anthropogenic climate change is leading to unprecedented changes that are, and will be, affecting both the biosphere and humanity in many ways [1]. To mitigate climate change, large reductions of CO_2 emissions are required. Decarbonizing the power sector is of particular importance, as this has the potential to happen more quickly than in the industrial, building and transport sectors [2].

Projections of decarbonized power sectors show that intermittent renewable energy sources (intermittent-RES) and power plants with Carbon Capture and Storage (CCS) will be important CO_2 mitigation options. They are projected to generate 20–80% (intermittent-RES) and 10–50% (power plants with CCS) of total electricity in Europe by 2050. The remainder is mainly generated by nuclear and non-intermittent renewable power plants [3–7].

As electricity demand and supply need to be kept in balance at all times, power systems will need to absorb the fluctuating electricity generation of intermittent-RES and account for intermittent-RES forecast errors [8,9]. Studies have shown that low-carbon power systems with large shares of intermittent-RES require more operational flexibility and more backup generation capacity. These requirements on the power system increase when intermittent-RES penetration increases [7,8,10].

Overall, the integration of intermittent-RES affects the power system in three ways: physically (how power generators are dispatched), economically (whether the business cases of all generators are sound), and in terms of security of supply (whether the power system meets its reliability targets).

Five complementary options have been suggested to improve the integration of intermittent-RES. Large scale electricity storage and expansion of interconnection capacity can balance supply and demand both temporally and spatially. Flexible natural gas-fired power plants with and without CCS can provide mid-merit and peak generation capacity at relatively low fixed costs. Demand response (DR) can reduce load during hours of capacity scarcity at low fixed costs, and hence reduce the peak generation capacity required. Lastly, curtailment of intermittent-RES generated electricity can be cost-effective [6,7,11].

Qualitative comparison between these five integration options have been made in the past [12–14]. These studies highlight the advantages and disadvantages of each technology, but they do not provide guidance on which options might be most suitable in future low-carbon power systems with varying deployment of intermittent RES.

Quantitative approaches are better suited to provide such guidance, but the fundamentally different principles of operation between the options complicate such an approach. Past studies have primarily focused on the optimal deployment level of a single type of complementary option. Examples include thermal power plants [15]; electricity storage [16]; and demand response [17]. In addition, some studies have quantified the effect of deploying one type of complementary option on another type of option: e.g. how interconnections and storage affect optimal thermal power plant deployment [18] and how demand response affects optimal interconnection capacity [19]. A last group of more comprehensive studies included all five complementary options in power system simulations. These studies focus on high-level conclusions and have not paid specific attention to the optimal deployment of complementary options, however [3,7,20].

As a consequence, there is insufficient understanding on which options are most suitable for low-cost integration of intermittent-RES in future low-carbon power systems. This knowledge gap has been identified by a number of studies [14,21,22]. Insights are needed to guide research and support policy makers and energy companies to identify and invest in portfolios of electricity generation, transmission and other complementary technologies that facilitate a cost-efficient, low-carbon future.

This study directly compares integration options for future low-carbon power systems by comparing the effect of their deployment on the total system costs. Thus, it answers the research question: ***Which complementary options should be deployed in low-carbon systems with high shares of intermittent RES to minimize total system costs?*** The study focusses on Western Europe in the year 2050 and simulates a reliable power system with a 96% reduction in CO_2 emissions compared to the year 1990. Two research steps are taken. First, the fossil generation capacity is least-cost optimized for plausible, exogenous scenarios with 40%, 60% and 80% RES penetration with varying shares of complementary options. Next, operation of the resulting full generation portfolios is simulated with a time step of 1 h to determine the total system costs.

This study accounts for intermittent-RES impacts on the power system, including increased sizes of balancing reserves, efficiency losses of thermal generators caused by intermittent-RES, displacement of thermal power generation and integration costs of intermittent-RES. The article focuses mainly on the simulation and calculation methods (Section 2), results (Section 4), discussion (Section 5) and Conclusion (Section 6). This study's input data are provided in Section 3 and Appendices A–G.

2. Methods

Western Europe is the study area, in which six regions are distinguished based on their prevalent types of intermittent-RES potential and the expected bottlenecks in future interconnection capacity between regions (see Fig. 1). Only transmission constraints between regions and not within regions are accounted for. The year 2050 is studied because a low-carbon power system is planned to be realized by then [23]. The period before 2050 is not simulated and no legacy power plants are included. Nevertheless, by varying the contribution of RES and intermittent-RES in 2050, insights are also obtained about the impact of an increasing contribution of intermittent-RES along the road towards 2050.

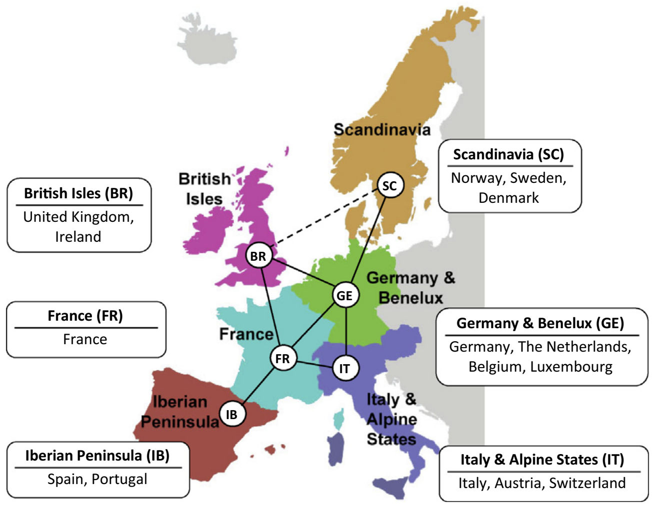

Fig. 1. Overview of the six regions considered in this study.

This study distinguishes between two groups of options: ***non-fossil*** generators[1] and ***complementary*** options. The latter consists of: (1) ***fossil*** generators[1]; (2) demand response (DR); (3) expanded interconnection capacities; and (4) electricity storage. Altogether these make up the ***full*** generation mix. *Non-fossil* capacity is defined exogenously per scenario. It is assumed that a low-carbon power system will be operating in 2050. Three core scenarios are explored with different levels of RES penetration on an energy basis: 40%, 60% and 80% RES.[2] These plausible are used scenarios rather than fully-optimized scenarios, as future energy prices are highly uncertain and a fundamental energy system transformation is likely to be both policy and price driven [24]. The research methods applied during our study consists of four main steps, illustrated in Fig. 2.

2.1. Define plausible non-fossil generation scenarios (Step 1)

Three plausible, exogenous, non-fossil generation scenarios are used in this study: 40%, 60% and 80% RES generation, which correspond to 22%, 41% and 59% intermittent-RES on an energy basis respectively. These are based on the scenarios of the Roadmap 2050 study of the European Climate Foundation (ECF) [3], which closely resemble the projections of the IEA Energy Technology Perspectives 2014 (ETP'14) study [6]. The shares of annual power generation are converted to installed capacities with the capacity factors used by the IEA [6].

We allocate intermittent-RES generation capacities to regions based on the potential intermittent-RES resource per region according to the method used in the Roadmap 2050 study of the ECF[3] [3]. Geothermal and hydropower generators are allocated to regions based on their future economic potential [25] and current deployment [26] respectively. Lastly, the thermal[4] generator capacity is equally divided over all regions so that the aggregate generation shares per technology in Western Europe match the predefined generation shares as shown in Fig. 3. Three additional assumptions are made: that no nuclear capacity will be installed in the region Germany & Benelux, that 50% of all nuclear generation capacity will be situated in France,[5] and that the ratio of biomass-generation versus fossil-generation will be five times higher in Scandinavia than in the other regions [7]. The resulting three scenarios of non-fossil generation portfolios for Western Europe in 2050 are shown in Fig. 3. In addition, the same amount of pumped-hydro capacity will be available as today in the non-fossil generation mix [27].

The relative composition of the *non-fossil* generation capacity is kept the same between scenarios, as well as the system reliability and emission cap to enable direct comparisons between scenarios.

2.2. Define capacities of complementary options (Step 2)

Next, the deployment of complementary options is exogenously defined. Three options are considered, of which the technical specifications are given in Sections 3.4–3.6:

(1) Five types of electricity storage: Pumped Hydro Storage (PHS), Compressed Air Energy Storage (CAES), as well as Redox flow, Sodium-Sulfur (NaS), and Li-ion batteries.[6]
(2) Demand Response (DR), which can either shed or shift load.
(3) Six levels of interconnection capacity between regions to balance load and supply.

2.3. Optimize fossil generation capacity with PLEXOS (Step 3)

In step three, the *fossil* generation capacity for the year 2050 is optimized with the PLEXOS tool. PLEXOS is also used to perform hourly simulations of the *full* generation mix in the year 2050 in step four of our analysis.

PLEXOS is a bottom-up integrated energy modeling tool developed by Energy Exemplar [28]. In this study, the model is used to optimize power system operations from a system perspective across timescales ranging from one reference year to one hour, by consecutively running three modules [29]:

(1) The LT plan is a mixed integer programming (MIP) tool to optimize investment decisions (timescale >1 year). Its objective is to minimize the sum of the net present value of build cost, Fixed Operation and Maintenance (O&M) costs and operational costs, while meeting minimum reliability and maximum emission requirements. 50 periods per month (600 per year) are simulated.
The model accounts for system reserves and predefined interconnection capacity between regions. The power system is simulated based on an *energy-only* market design (i.e. no capacity mechanisms or subsidy schemes are considered). The residual value of investments is calculated by assuming that the year 2050 is repeated until perpetuity.
(2) The *MT schedule* translates annual constraints, such as hydropower generation and planned outages, to weekly constraints as an input to the ST schedule. The MT schedule is based on 25 periods per week, so 1300 per year.
(3) The *ST schedule* is a MIP tool for chronological optimization of unit commitment and economic dispatch (UCED) decisions. It minimizes the total cost of generation whilst meet-

[1] An overview of all included non-fossil and fossil generator types is provided in Table 4.

[2] The capacity mix of low-carbon scenarios from scenario studies for 2050 in Europe was explored, and showed that intermittent-RES and low-carbon thermal capacity can be deployed interchangeably whilst meeting the required CO_2 emission reductions [3–5,7,103,104] Our scenarios are therefore considered plausible.

[3] Generation capacity is allocated to regions based on expert ranking from the ECF Roadmap 2050 study. The six regions are ranked 1–6, where the region with the best resource base receives the highest grade. The region's share is then calculated by dividing the region's grade by the sum of all grades [3].

[4] Thermal capacity includes nuclear and biomass capacity, as well as fossil fuel capacity. The specific composition of the fossil fuel capacity is determined in the optimization of Step 3.

[5] The resulting installed nuclear capacity in France in 2050 is 12–64% lower than the nuclear cap of 63 GW announced in 2014.

[6] Hydrogen storage by converting electricity to hydrogen is not evaluated, as explained in Appendix G.

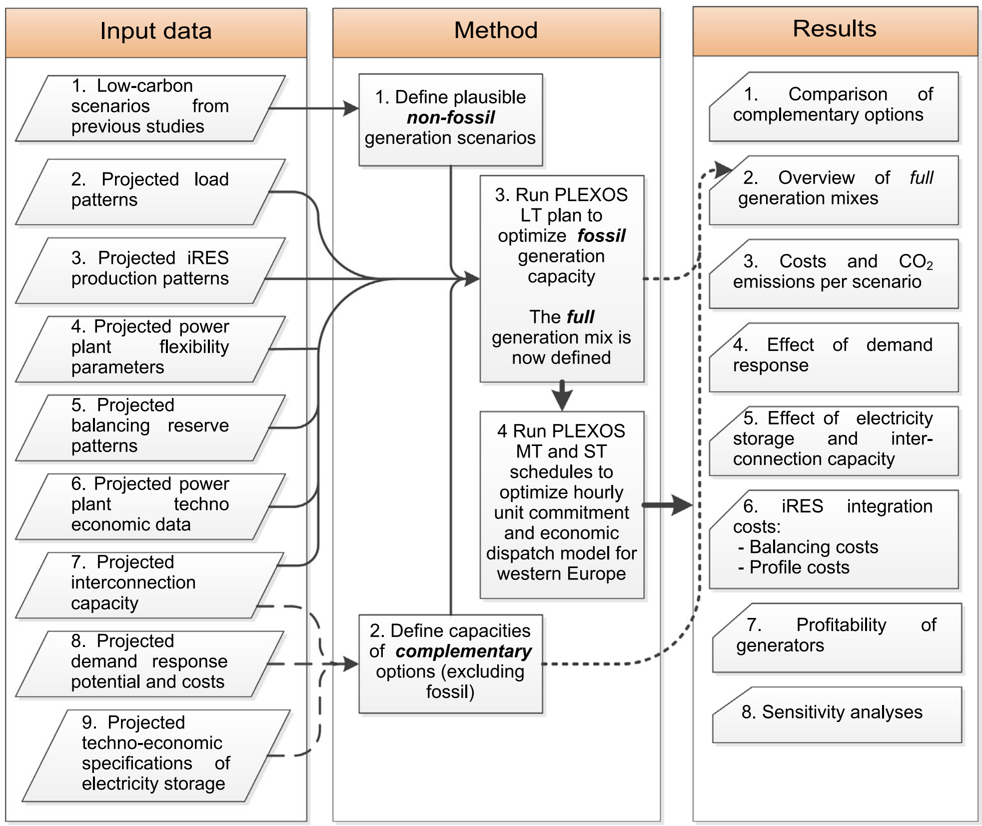

Fig. 2. Flow chart description of study methods.

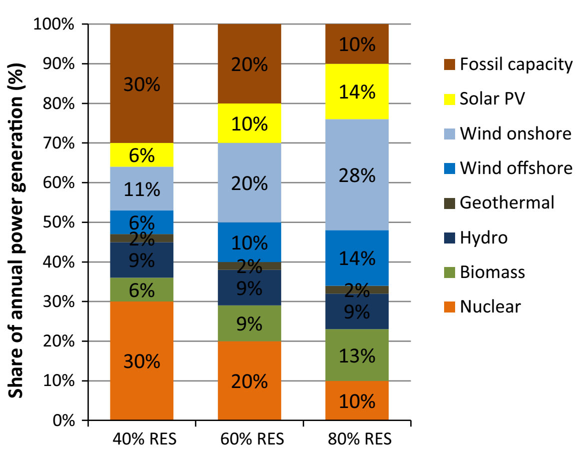

Fig. 3. The composition of *fossil* and *non-fossil* annual electricity generation per generator type per scenario in 2050. The composition of the *fossil* electricity generation is optimized in this study.

ing five constraints: (1) electricity supply must be equal to demand; (2) the flexibility constraints of the generators; (3) limited transmission capacity of interconnectors; (4) scheduled and unscheduled (random) outages of power plants; and (5) the balancing reserve requirement of the system. It has a time step of one hour. An energy-only market is simulated, without including revenues from delivering ancillary services.

We determine the *full* generation mix for each run by calculating the least cost additions of *fossil* generation capacities to the generators and complementary options defined in steps one and two. In our study, five types of fossil fuel power plants can be built: pulverized coal plants without and with CCS (PC, PC-CCS), natural gas combined cycle plants without and with CCS (NGCC, NGCC-CCS) and gas turbines (GT). In addition, the model has the possibility to invest in extra biomass-fired power plants on top of the exogenously defined capacity.

The solution has to satisfy a reliability criterion of <0.2 days of non-availability per year. The reliability is based on the load and the capacity that is available to meet it (accounting for capacity credits of intermittent-RES, and the capacity of other generators minus unscheduled outages). Capacity credits of wind and solar PV were determined to be 5% and 0% of installed capacity respectively, based on hourly load and intermittent-RES patterns for the year 2050 [30].

Moreover, the solution has to satisfy an emission cap of 45 $MtCO_2$ per year, equivalent to a 96% reduction in power sector CO_2 emissions compared to the year 1990 [31]. This would meet the EU target of reducing power sector CO_2 emissions by 93–99% in the year 2050 [5].

2.4. Run hourly simulations with PLEXOS (step 4)

The three core scenarios are simulated with the ST scheduling module of the PLEXOS tool. Additional runs were performed to assess the impact and performance of the complementary options (Table 1). In addition, two 17% and 18% RES scenarios with 0% and 1% intermittent-RES respectively are created from the 40% RES scenario. These scenarios serve as a base-case for intermittent-RES integration cost calculations.

Eight providers of system flexibility are considered in this study, as shown in Table 2. Some sources can provide spinning reserves (fast reserves, available within 5 min), and standing reserves (slower reserves, available within 1 h) [see Appendix D].

Table 1
Overview of model runs, and deployed complementary options.

Set of runs	Non-fossil capacities	Complementary options				Curtailment
		Fossil	Demand response[a]	Interconnection capacity[b]	E-storage[c] (type)	
Core cases	17[d]/40/60/80% RES	Optimized	47 GW	189 GW	39 GW PHS	Optimized
Additional runs						
Effect of interconnections and E-storage	40/60/80% RES	Optimized	47 GW	37–349 GW	39 GW PHS + 0–95 GW CAES	Optimized
Effect of DR	40/60/80% RES	Optimized	0–94 GW	189 GW	39 GW PHS	Optimized
Effect of intermittent-RES on power system	17/18/40/41/60/61/80/81% RES	Optimized	47 GW	189 GW	39 GW PHS	Optimized
Other sensitivity runs	40/60/80% RES	Optimized	47 GW[e]	189 GW[e]	39 GW PHS[e]	Optimized

[a] Based on projections of [32].
[b] Based on projections of [3,33]. 189 GW is a significant increase from the 37 GW installed today.
[c] The current installed PHS capacity is 39 GW [27]. CAES is built as it is expected to be the cheapest storage technology based on an exogenous analysis (Fig. 9, Appendix G).
[d] In addition, a 17% RES run without a CO_2 emission cap is run as a base case to calculate the CO_2 avoidance cost.
[e] Varied in the sensitivity analysis.

Table 2
Providers of system flexibility, and the reserves they can potentially provide.

	Ramping up/down	Spinning up[a]	Spinning down[a]	Standing up[a]	Standing down[a]
Ramping of online thermal power plants	✓	✓	✓	✓	✓
Fast-start of natural gas fired power plants	✓			✓	
Charging electricity storage	✓		✓		✓
Discharging electricity storage/hydropower	✓	✓		✓	
Curtailment of wind power	✓		✓		✓
Un-curtailment of wind power	✓	✓		✓	
Demand response[b]	✓				
Interconnection capacity	✓				

[a] Providing spinning and standing reserves is mutually exclusive.
[b] Demand response was does not provide reserves in this study, because it is unclear which share of the demand response can reliably provide reserves within short time frames [6].

2.5. Integration costs of intermittent-RES

The integration of any generator type in power systems incurs external costs, such as costs for the grid connection, and balancing costs to counter potential outages. For intermittent-RES, these integration costs may be a considerable component of their total generation cost [34], so they are quantified in this study. Three types of integration costs are described in the literature: balancing, profile and grid costs [34,35]. The integration costs are expressed as a function of the driving factor: intermittent-RES penetration. Penetration levels of 0%, 22%, 41% and 59% intermittent-RES are considered, which correspond to 17%, 40%, 60%, and 80% RES scenarios.

Balancing costs are caused by the limited predictability of intermittent-RES, which necessitates larger operating reserves. These costs are calculated for every time step (t), region (r) and reserve type (rt) based on the shadow price of the of the reserve type constraint (the price of delivering 1 MW of extra reserve capacity for each combination of t, r and rt) (Eq. (1)).

$$C_{\text{balancing,specific}} = \left(\sum_{t,r,rt} \text{Shadowprice}_{t,r,rt}^{\text{reserves,specific}} * \text{Requirement}_{t,r,rt}^{\text{reserves}}\right) / E_{\text{iRES}} \tag{1}$$

$C_{\text{balancing,specific}}$ = specific balancing costs (€/MW h_{iRES})
Shadow $\text{price}_{\text{reserves,specific}}$ = specific shadow price of reserves (€/MW h)
$\text{Requirement}_{\text{reserves}}$ = reserve requirement (MW)
E_{iRES} = annual intermittent-RES production (MW h/yr)
t = hourly time slice
r = region
rt = reserve type

Profile costs are caused by the intermittent nature of intermittent-RES, and comprise two main types of integration costs [34,35]. First, power generation by intermittent-RES may lead to reduced utilization of residual (non-iRES) generation capacity: "residual system utilization costs"[7]. Second, power generation by intermittent-RES can be curtailed: "curtailment costs". Both costs from the operation of power plants are determined using the method proposed by Hirth [34] (Eqs. (2)–(4)). Hirth also defines flexibility costs, but these are not included as they are minimal (<0.01 €/MW h_{iRES}).

$$C_{\text{utilization,specific}} = \left(\left(\frac{\sum_{\text{rg}} C_{\text{rg}}}{\sum_{\text{rg}} E_{\text{rg}}} - \frac{\sum_{\text{rg}} C_{\text{rg}}^{0\%\text{iRES}}}{\sum_{\text{rg}} E_{\text{rg}}^{0\%\text{iRES}}}\right) * E_{\text{resid}}\right) \Big/ E_{\text{iRES}} \tag{2}$$

$C_{\text{utilization,specific}}$ = specific utilization costs (€/MW h_{iRES})
C = annual cost (€/yr)
E = annual electricity generation (MW h/yr)
$C_{0\%\text{iRES}}$ = annual cost in the 17% RES (0%iRES) scenario (€/yr)
$E_{0\%\text{iRES}}$ = annual electricity generation in the 17% RES (0%iRES) scenario (MW h/yr)
E_{resid} = annual residual electricity generation (MW h/yr)

[7] The utilization costs closely match the profile costs as proposed by Ueckerdt et al. (±1%) [35] (Eq. (5)).

$$C_{\text{profile,specific}} = \left(\left(\frac{C_{\text{system,resid}}}{E_{\text{resid}}} - \frac{C_{\text{system,0\%iRES}}}{E_{0\%\text{iRES}}}\right) * E_{\text{resid}}\right) \Big/ E_{\text{iRES}} \tag{5}$$

$C_{\text{profile,specific}}$ = specific profile costs (€/MW h_{iRES}); $C_{\text{system,resid}}$ = annual residual system costs (€/yr); E_{resid} = annual residual electricity generation (MW h/yr); $C_{\text{system,0\%iRES}}$ = annual system costs of the 17% RES (0%iRES) scenario (€/yr); $E_{0\%\text{iRES}}$ = annual electricity generation in the 17% RES (0%iRES) scenario (MW h/yr); E_{iRES} = annual intermittent-RES production (MW h/yr)

E_{iRES} = annual intermittent-RES production (MW h/yr)
r = region
g = generator

$$C_{\text{overproduction,specific}} = \sum_{\text{iRES}} C_{\text{iRES}}^{\text{specific}} * \left(1 - \frac{E_{\text{iRES}}^{\text{delivered}} - E_{\text{iRES}}^{\text{curtailed}}}{E_{\text{iRES}}^{\text{delivered}}}\right) \tag{3}$$

$C_{\text{overproduction,specific}}$ = specific overproduction costs (€/MW h_{iRES})
$C_{\text{iRES,specific}}$ = specific intermittent-iRES cost (€/MW h_{iRES})
E_{iRES} = energy of intermittent-RES generator (MW h/yr)
iRES = type of intermittent-RES generator

$$C_{\text{profile,specific}} = C_{\text{utilization,specific}} + C_{\text{overproduction,specific}} \tag{4}$$

$C_{\text{profile,specific}}$ = specific profile costs (€/MW h_{iRES})
$C_{\text{utilization,specific}}$ = specific utilization costs (€/MW h_{iRES})
$C_{\text{overproduction,specific}}$ = specific overproduction costs (€/MW h_{iRES})

Both types of cost are calculated by comparing the 22/41/59% intermittent-RES penetration to a 0% intermittent-RES low-carbon base case. In addition, the marginal integration costs are calculated by attributing the marginal change in costs to the marginal increase in intermittent-RES capacity to 1/23/42/60% intermittent-RES penetration.

Grid costs are related to the variation in market value of electricity depending on where it is generated in the grid [34]. It captures aspects such as grid congestion and the opportunity costs of transmitting power from where it is generated to where it is consumed. Due to the regional copper plate assumption in this study, total grid costs cannot be determined.

3. Input data

An overview of the key input parameters is provided in this section. Further input data including load patterns, intermittent-RES generation patterns and balancing reserves are provided in Appendices A–G. Whenever possible, input data from the IEA are used to ensure internal consistency. All costs are expressed in €$_{2012}$.

3.1. Fuel prices

Fuel prices are based on the low-carbon 2DS scenario of the IEA Energy Technology Perspectives 2014 [6], see Table 3.

Table 3
Fuel and CO_2 prices in 2050 used in this study.

Fuel/CO_2 prices[a]	Cost (range)	Reference
Coal	1.7 €/GJ	[6]
Natural Gas	6.5 €/GJ (3.9–7.8)	[6]
Uranium	1 €/GJ	[7,36]
Biomass	7.2 €/GJ (5.5–7.2)	[6][b]
CO_2 transport & storage	13.5 €/tCO_2[c]	[37,38]

Energy prices were converted with an exchange rate of 1$ = €0.78.
[a] Fuel prices may be influenced by the deployment of RES, because it decreases fuel offtake. The effect of changing fuel prices is quantified in the sensitivity analysis.
[b] Price is based on personal communication with the authors. Range shows a situation in which biothermal generators shift to an earlier position in the merit order than NGCC-CCS plants, as studies indicate that biomass production costs may be lower [39,40].
[c] Cost of €3.5/tCO_2 for transport (±€1.5) [37], and €10/tCO_2 for storage in saline aquifers (±€9) [38].

3.2. Load and intermittent-RES patterns

Load patterns are based on the historical load patterns per country of 2013 [41], which increases by 0.25% per year to 2800 TW h in 2050 based on the IEA ETP'14 2DS scenario [6]. A summary of electricity demand characteristics is provided in Appendix A.

Generation patterns of wind and solar PV are calculated based on meteorological observations for the year 2013. This year is representative in terms of wind and solar PV generation. Also, historical intermittent-RES generation data is available to validate the calculated time series. Comparing the calculated and historical wind data series of 3 regions shows a strong correlation (r^2 = 70–86%) and similar average step change (difference ±15%) and standard deviation (difference ±30%). Solar PV has a very strong correlation (r^2 > 98%) and similar average step changes and standard deviations (difference in both ±3%). More details are provided in Appendix B.

3.3. Power plant parameters

This study considers 12 types of power plants, which are shown in Table 4 along with their techno-economic parameters based on the IEA World Energy Outlook 2014 [42]. Only fully biomass-fired power plants are included, as previous studies do not communicate projections on co-firing biomass [3,4,6]. Also, no biomass power plants with CCS are included, based on IEA projections [6]. The IEA outlook accounts for learning based on global deployment projections. It does not distinguish between fixed and variable O&M costs, so they are decomposed based on an earlier analysis by the authors [11]. Flexibility parameters are taken from the same study [11], as specified in Appendix C.

Only a snapshot of the year 2050 is considered in this study, which disregards the presence of vintage power plants. To account for these, the techno-economic parameters of all power plants operational in the year 2050 are based on those of plants from the year 2035, which likely reflect the average parameters of all power plants in the year 2050.

3.4. Interconnection capacity

We consider eight interconnectors in this study, as shown in Fig. 1. Six interconnection cases are considered, ranging from the installed capacity of 37 GW in 2014 [45] up to 349 GW for 2050 in scenarios with high shares of renewables as shown in Fig. 4 [3,46]. Note that the planned interconnector between the British Isles and Scandinavia is only present in the "High" and "Maximum" cases. Average annual costs of 28,000 €/MW/yr are used to assess the benefits of interconnection capacity [14,47]. More information is provided in Appendix E.

3.5. Demand response

Deployment of demand response (DR) is based on estimates of the theoretical potential by Gils [32], and estimates of deployment by Bertsch et al. [7]. Industrial, commercial as well as residential loads are considered, which can be altogether reduced (shed), or moved in time (shifted). The composition of the resulting 47 GW of DR capacity is shown in Fig. 5. Costs of load shedding range between 200 and 5000 €/MW h [48], and investment costs for load shifting range from 2 to 100 €/kW [49]. Techno-economic details are provided in Appendix F.

Table 4
Projected techno-economic parameters of power plants for 2035 [42].

Generator type	TCR investment[a] $€_{2012}$/kW	Fixed O&M $€_{2012}$/kW	Variable O&M $€_{2012}$/MW h	Full load efficiency % LHV	Lifetime years
Fossil generators[b]					
Gas turbine (GT)	438	10	0.8	42%	30
Natural Gas Combined Cycle (NGCC)	902	11	1.2	63%	30
Pulverized coal (PC)	2088	29	4.6	49%	40
NGCC with CCS (NGCC-CCS)	1349	15	2.1	56%	30
PC with CCS (PC-CCS)	2847	33	5.6	41%	40
Non-fossil generators					
Nuclear power	4841	103	0.0	33%	50
Wind onshore	1402	37	0.0	–	25
Wind offshore	2655	83	0.0	–	25
Solar PV	700[c]	17	0.0	–	25
Biomass power plant	1644	37	3.1	45%[d]	40
Geothermal power	2151	44	0.0	–	40
Hydropower	2059	52	0.0	–	40

[a] The Total Capital Requirement (TCR) investment costs are calculated from the Total Overnight Costs (TOC) reported by the IEA [42]. An interest percentage of 8% of is used during construction. The capital expenditures occur linearly during the construction phase [43].
[b] Power plants only generate electricity: no combined heat and power plants are included.
[c] The investment costs of solar PV are based on IEAs Energy Technology Perspectives 2014, as those projections correspond better with current developments.
[d] This efficiency is based on the premise that the power plant is fired with a dedicated, high quality biomass fuel. Its' efficiency is 91% of that of a supercritical PC-plant [44].

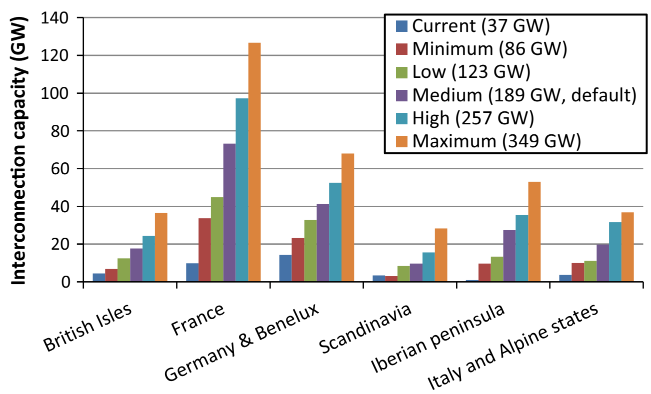

Fig. 4. Interconnection capacities between regions used in this study.

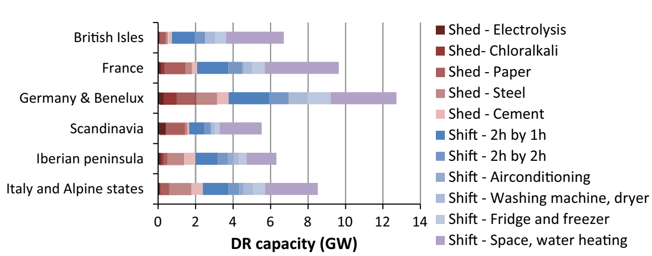

Fig. 5. Demand response capacities per region used in this study.

3.6. Electricity storage parameters

The techno-economic parameters of electricity storage are based on present-day specifications reported by the IEA, and vendor quotes [6,50,51]. In addition, significant technological learning is projected to occur for each technology, as described in Appendix G. The resulting input parameters are shown in Table 5. Power-to-Gas is not considered in this study because other studies indicate that this option may not be attractive until about 80% intermittent-RES penetration [22,52].

4. Results

Sections 4.1–4.3 present the main modelling results from the 17%, 40%, 60% and 80% RES core scenarios. Sections 4.4 and 4.5 explore the effect of extra complementary options, and Sections 4.6–4.7 zoom in on the costs of the core scenarios. Section 4.8 provides a sensitivity analysis.

4.1. Overview of full generation mixes

Fig. 6 shows the full generation mixes of the core scenarios. The generation mix of the year 2012 is also shown as a reference. Recall that intermittent-RES capacities increase and nuclear capacities decrease as defined exogenously for each scenario. After

Table 5
Projected techno-economic parameters of electricity storage in 2050.

Technology	Progress rate (%)	Number of doublings[a] #	2050 TCR investment[b] ($€_{2012}$/kW)	2050 TCR investment[b] ($€_{2012}$/kW h)	Round trip efficiency (%)	Lifetime (years)	Construction time (years)	Battery replacement costs[c] ($€_{2012}$/kW)	O&M costs (% of invest)
PHS	99	1.3	1101	67	77	40	4	–	1
CAES[d]	95	9.1	646	29	63	35	4	–	5
NaS	90	10.0	410	121	80	12	1	–	5
VRB	90	11.1	260	149	75	12	1	171	3
Li-ion	90	11.6	541	344	85	12	1	265	3

PHS: Pumped Hydro Storage; CAES: Compressed Air Energy Storage; NaS: Sodium-Sulfur batteries; VRB: Vanadium Redox Battery; Li-ion: Lithium ion battery.
[a] Number of doublings of cumulative built capacity. Based on the current installed capacities and worldwide deployment of intermittent-RES in the 2DS of the IEA ETP'14 [6].
[b] Total investment costs are composed of the cost of output capacity (in kW) and costs of the storage reservoir (in kW h). All technologies have 8 kW h of storage capacity for every kW of capacity. The Total Capital Requirement (TCR) investment cost includes the Interest During Construction (IDC). This IDC is based on the construction time and a discount rate of 8%.
[c] Battery replacement costs required during the lifetime of the battery system.
[d] Adiabatic CAES is used in this analysis.

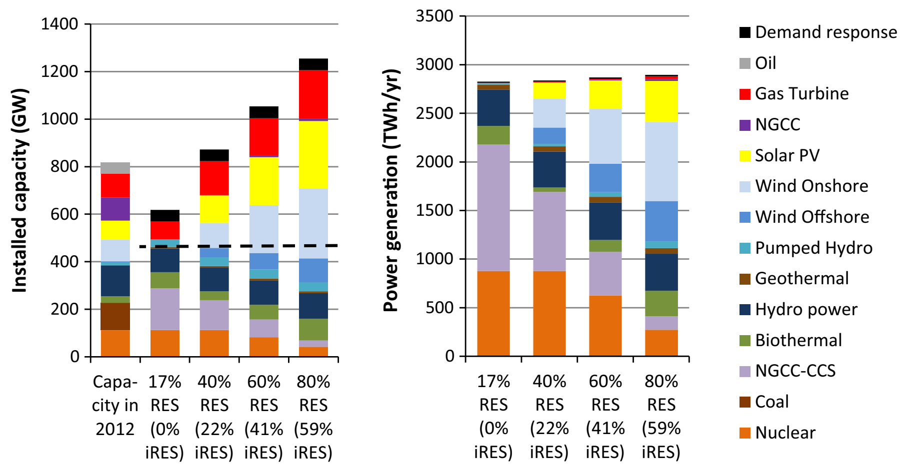

Fig. 6. Breakdown of installed capacities and power generation in the core scenarios in the year 2050. The dashed line depicts the peak load in 2050.

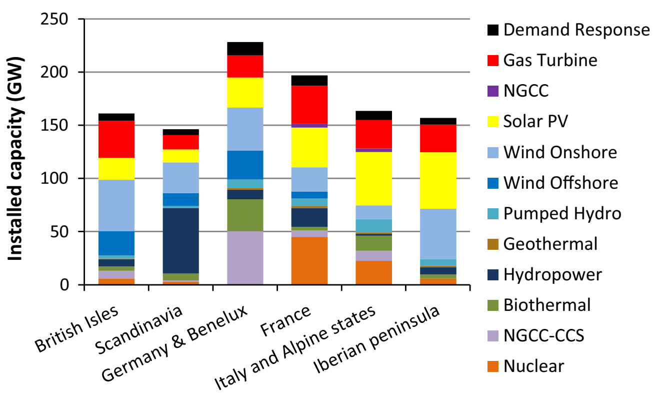

Fig. 7. Installed capacities in the 60% RES scenario per region.

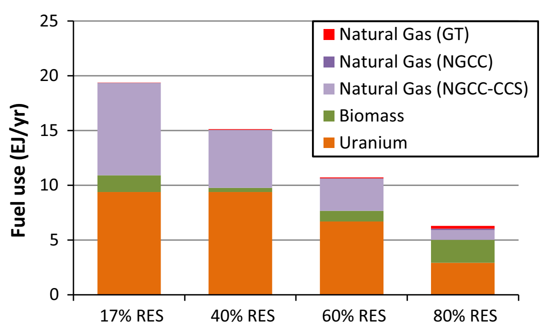

Fig. 8. Fuel use of power generation in Western Europe in 2050 for the core scenarios.

optimization of the fossil generation capacity, it is found that (see Figs. 6 and 7):

– Only GT and NGCC-CCS capacities are built as optimized fossil generation capacity,[8] because these are the least-cost generators (Fig. 9).
– Increasing RES capacity lowers the residual load, which decreases the NGCC-CCS capacity to be installed. In contrast, more GT capacity is installed with increasing RES capacity, because intermittent-RES requires a cheap provider of capacity to ensure system adequacy.
– The bulk of energy generation is provided by intermittent-RES, nuclear, hydropower and NGCC-CCS generators. Peaking options such as GTs and DR have low capacity factors (<5%, see Fig. 18). This can also be seen from the fuel use, which is dominated by uranium and natural gas for NGCC-CCS plants (Fig. 8).

Interregional differences can be seen in terms of the penetration of intermittent-RES and the dominant dispatch technologies. Scandinavia has high shares of hydropower, whereas Germany and Benelux have high shares of NGCC-CCS plants because no nuclear power is assumed in these regions. The British Isles and the Iberian Peninsula have very high shares of intermittent-RES, which they export during hours of high production.

Total fuel use decreases as RES generate more electricity, but the demand becomes more variable. This means that the infrastructure to supply fuels will have a lower capacity factor, which will increase the infrastructure costs per unit of fuel delivered. For example, peak demand for natural gas is only 3% lower in the 80% RES scenario than the 40% RES scenario, although the average offtake is 76% lower in the 80% RES scenario.

4.2. Comparison of complementary options

An overview of complementary options with the lowest levelized cost of electricity (LCOE) is provided in Fig. 9. The LCOE of all options is affected by the capacity factors (*x*-axis), and the LCOE of storage technologies is affected by the average cost of charging (*y*-axis). Interconnection capacity and curtailment are not shown because they cannot directly generate electricity. The results show that:

– As expected, options with low fixed costs perform better at lower capacity factors. Storage options benefit from low electricity prices for charging.
– DR-shed (black stripes) and DR-shift (grey stripes) are cost effective options but with limited capacity, so the next-cheapest option, GT capacity (red), is also deployed. The stripes depict the limited DR capacity.

[8] Biothermal capacity is built in the 17% RES scenario to meet the CO_2 emission constraint.

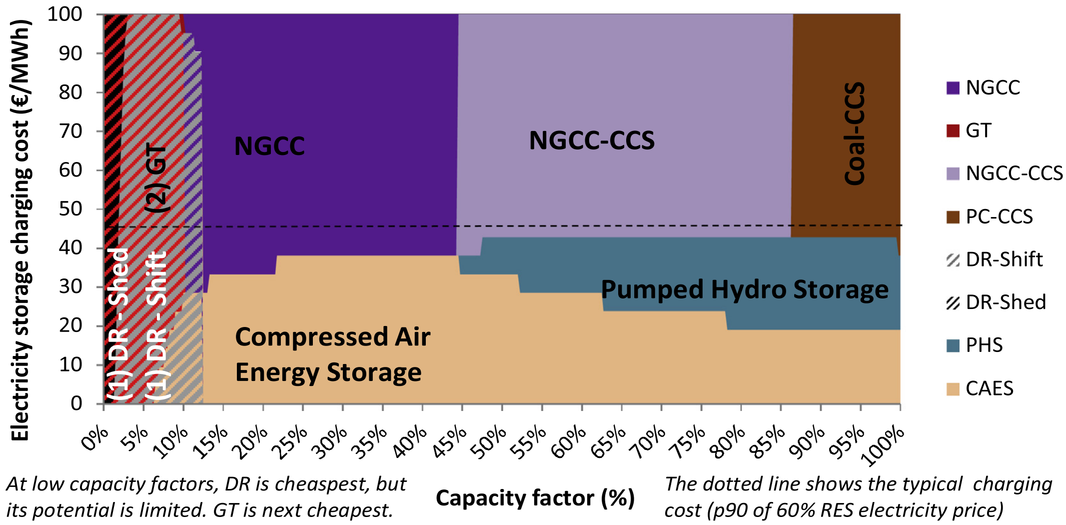

Fig. 9. Overview of complementary options with the lowest LCOE at a CO_2 price of 70 €/tCO_2. Graph is based on simulated electrical efficiencies of thermal generators.

- NGCC plants are the cheapest complementary technology at capacity factors of 10–44%, but the tight CO_2 emission cap results in NGCC-CCS capacity being installed and operated instead at these and higher capacity factors.
- Coal-CCS has the lowest LCOE only at high capacity factors (>86%), which are not realized in our scenarios for the year 2050. Nuclear capacity is >15% more expensive than coal-CCS at any capacity factor due to its high investment costs, and is therefore not depicted. Note that nuclear is exogenously included in the scenarios.
- CAES is the lowest-cost storage technology. PHS would theoretically have lower costs at capacity factors of >45% due to its higher round-trip efficiency, but the maximum annual capacity factor of electricity storage is 33% for a single daily cycle with 8 h of storage capacity.
- Of the options depicted in Fig. 9, only fossil-fuel fired power generators can supply inter-seasonal flexibility. The DR and storage technologies considered in this study lack the storage capacity to do this. Power storage that can provide inter-seasonal storage (e.g. hydrogen storage) is prohibitively expensive [6].
- The simulated electricity prices during off-peak hours, which electricity storage has to pay for charging, are too high to make storage the least-cost option.
- Within energy storage, the LCOEs of battery options are higher than that of CAES due to higher investment costs (LCOEs are 350–750 €/MW h compared to 200 €/MW h for CAES at a 10% capacity factor, and 200–400 €/MW h compared to 150 €/MW h for CAES at a 20% capacity factor). Thus, currently available batteries technologies are expected to be less attractive than CAES from a macro-economic perspective, unless supported by a policy framework or micro-economic advantages (e.g. a solar PV and battery combination for households).

4.3. Costs and CO_2 emissions per scenario

The total annual system costs are dominated by fixed costs (investment and fixed O&M costs, see Fig. 10). These costs increase at higher levels of RES due to the relatively high fixed costs of intermittent-RES, and due to thermal capacity running at reduced capacity factors (resulting in profile costs, see Section 4.6).

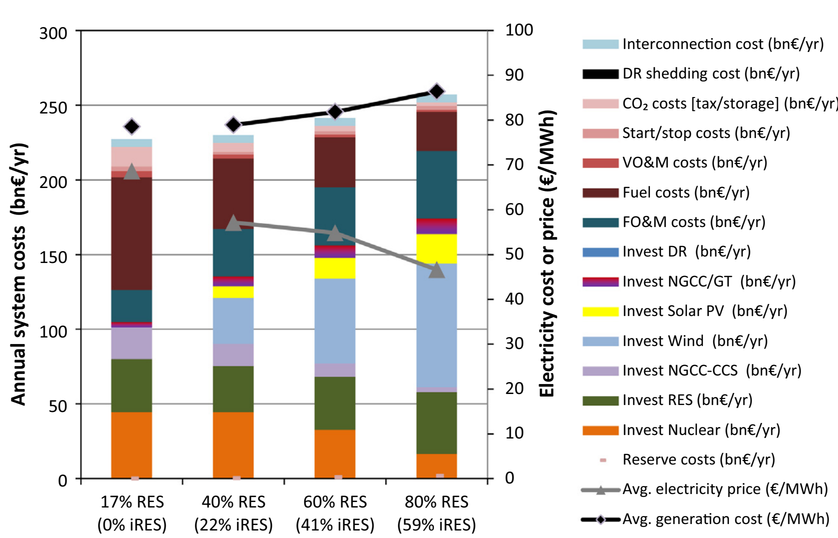

Fig. 10. Total annual system costs in the core scenarios in Western Europe in 2050, as well as the average production cost and market price per MW h.

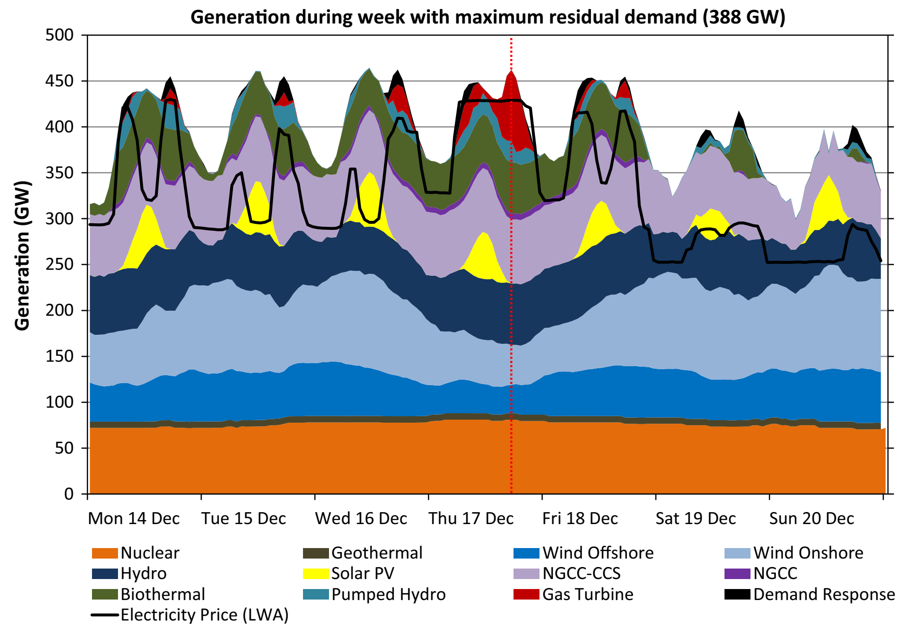

Fig. 11. Hourly generation profile for the week in 2050 with the highest residual load in the 60% RES scenario. The black line depicts the load weighed average electricity price.

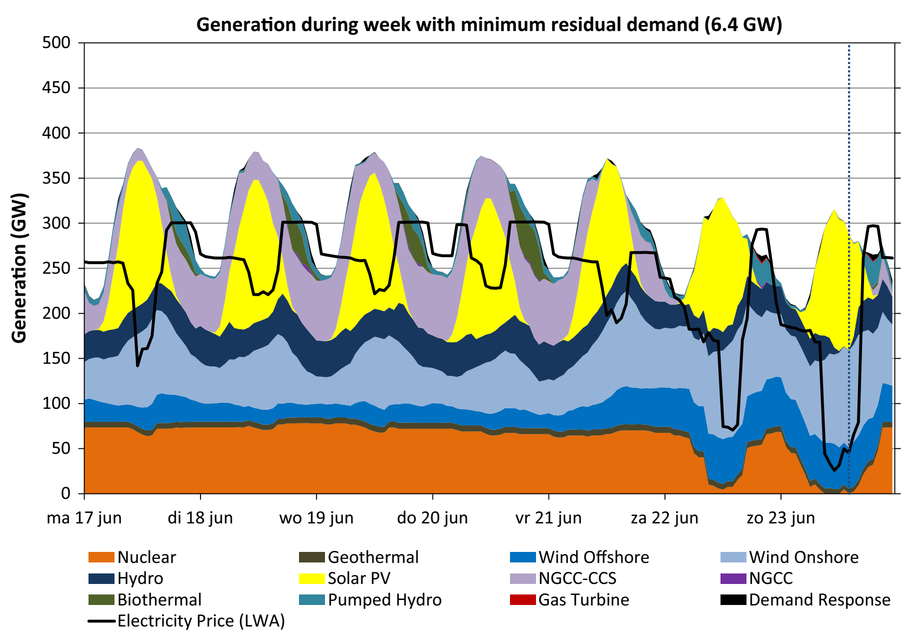

Fig. 12. Hourly generation profile for the week in 2050 with the lowest residual load in the 60% RES scenario. The black line depicts the load weighed average electricity price.

Annualized investment costs of the 189 GW of regional interconnectors are sizable (5 bn€/yr), but comprise only 2% of total system costs.[9] Variable costs (fuel, variable operation and maintenance, CO_2 and start/stop costs) decrease with higher levels of RES, though at a slower rate than the increase in fixed costs. Overall, this leads to increasing total system costs with higher RES penetrations.

The lower total system costs of the 40% RES scenario compared to the 80% RES scenario shown in Fig. 10 is the result of thermal capacity being cheaper than RES capacity. More specifically, intermittent-RES capacity is replaced by nuclear and NGCC-CCS capacity (Fig. 6). As nuclear capacity is relatively expensive (it is not depicted in Fig. 9), the 12% reduction in total system costs can be attributed to the larger NGCC-CCS capacity.

In addition, the low marginal cost of RES reduces average electricity prices, which leads to an increasing gap between the costs and revenues of the power system. Note that this study enforces a fixed exogenous reliability criterion, which ensures sufficient capacity is installed, irrespective of whether or not their business cases are sound.

The weeks with the highest and lowest residual load are shown in Figs. 11 and 12 respectively for the 60% RES scenario. The figures

[9] Transmission and distribution capacity within regions is not included in this sum. They comprise 6% and 20–25% of total power sector investments, respectively [42].

Table 6
Curtailment and decreased efficiency in the core scenarios.

	17% RES	40% RES	60% RES	80% RES
Curtailment [% of potential intermittent-RES generation]	0%	0%	0.1%	2.0%
Average increased fuel use (except GT)[a]	+9.4%	+9.5%	+9.5%	+9.7%
Average increased fuel use of GTs[a]	+22%	+23%	+27%	+29%

[a] The increased fuel use compared to their maximum (full-load) efficiency. In a power system without intermittent-RES (17% RES scenario), increased fuel use is caused by the variability in load.

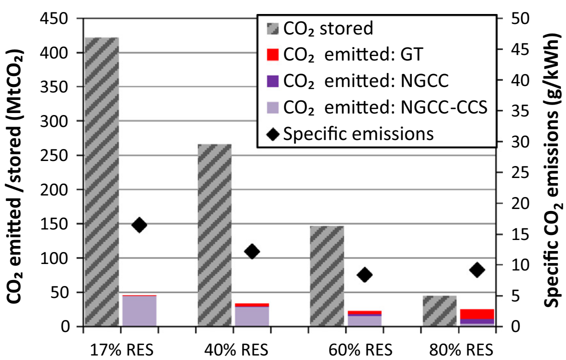

Fig. 13. CO_2 emitted, CO_2 stored and specific CO_2 emissions per scenario in Western Europe in 2050.

also show the dispatch of base-load plants (nuclear, geothermal and intermittent-RES), mid-merit plants (NGCC-CCS and hydropower) and peak-load plants (biothermal, NGCC, and GT) in Western Europe. Moreover, pumped hydro storage and demand response cover evening demand after the sun has set.

In the maximum residual load week, the power generation of solar PV is relatively low, leading to high residual load. This load is fulfilled by dispatching all types of generation capacity, including biothermal and GT plants. Wind power generation turned out not to be at its lowest point during this week (74 GW of generation). In some summer weeks, wind generation is as low as 17 GW, but because of a lower load, the residual load is also smaller.

In summer months, solar PV generation is higher, which requires dispatchable power plants to ramp down or switch off altogether during some daytime hours. During the night, some NGCC-CCS and biothermal plants are switched on again, which is allowed by their improved flexibility compared to today's specifications. Spinning reserves are provided by hydropower and (curtailed) intermittent-RES generators, the former of which can supply large amounts of reserves at low costs. Standing reserves are also provided by GT plants.

The effect of renewables on power generators is limited for the considered penetration levels, but it increases with higher RES penetration (see Table 6).

– Increased RES capacity leads to some intermittent-RES curtailment, especially in the 80% RES scenario. It is cheaper to curtail this power than to deploy storage to store it: 50 GW and 100 GW of storage capacity with 8 h of storage are required to reduce curtailment to 1.1% and 0.7% in the 80% RES scenario, respectively, increasing total system costs by ~1% and ~2%.
– The effect of intermittent-RES on the conversion efficiencies of power plants is limited: compared to the 17% RES scenario with 0% intermittent-RES, power plant fuel use increases by 0.1–0.3%. Exceptions are GT plants, which are more adversely affected due to part-load operation. In general, extra flexibility is provided by switching on/off generation units rather than running at part-load.

The annual CO_2 emissions between the scenarios are comparable, as shown in Fig. 13. This shows that the same CO_2 cap can be reached

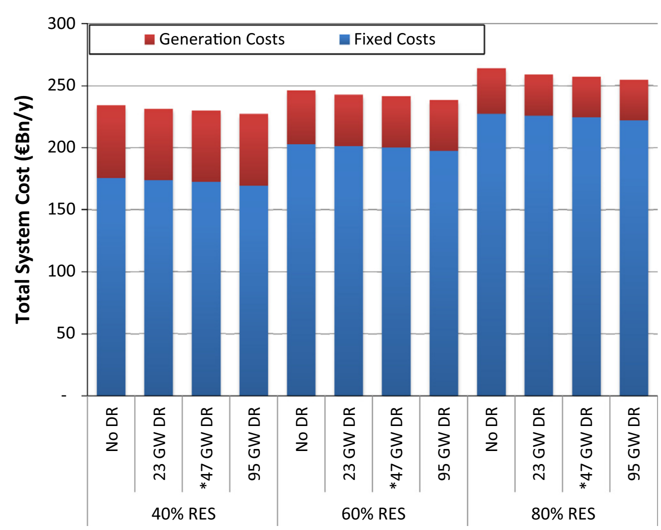

Fig. 14. Effect of demand response on total annual system costs. * denote the core scenarios.

Table 7
Average CO_2 abatement cost per scenario in the year 2050 compared to a 17% RES scenario without a CO_2 cap.[a,b]

	17% RES	40% RES	60% RES	80% RES
Average CO_2 abatement cost [$€_{2012}/tCO_2$]	64	67	85	112

[a] This calculation assumes no change in fuel price. If higher fuel prices are used for the 17% RES scenario without a CO_2 emission cap, which is plausible in a cap-less scenario, avoidance costs decrease to 25, 27, 39 and 55 €/tCO_2 respectively. These costs are based on prices of 3.6 €/GJ for coal and 11.6 €/GJ for natural gas from the 6DS scenario from the ETP'14 [6].
[b] The CO_2 abatement costs give a better impression of the cost of CO_2 emission mitigation, because CO_2 prices are the same in all scenarios. This is the result of the same generator types being installed in the 40%, 60% and 80% RES scenarios. The deployment of RES is not driven by the CO_2 price, but by the scenarios. For the scenarios, the PLEXOS model calculates an internal CO_2 price of 70 €/tCO_2 during the optimization of fossil capacity, which is used for the MT and ST schedules. The most expensive abatement option (offshore wind) would require a CO_2 price of 126 €/tCO_2 to replace NGCC generation.

with either higher shares of NGCC-CCS or RES,[10] but at different costs. High shares of RES enable other generators to have higher specific emissions. Hence, more NGCC and GT capacity is built and utilized in high-RES scenarios, because these generators have a lower LCOE than NGCC-CCS plants at capacity factors below 45% (see Fig. 9).

These reductions of CO_2 emissions require extra investments compared to a scenario without an emission cap. To quantify these, the average CO_2 abatement cost were calculated compared to a 17% RES scenario without an emission cap, see Table 7. This cost is distinct from the CO_2 price, the latter being the abatement cost of the most expensive (i.e. marginal) emission abatement option that is deployed.

4.4. Effect of demand response

DR reduces total system costs by 1.7–2.5% in the 47 GW DR core scenarios compared to a situation without DR. It does this in two ways. Firstly, DR reduces total generation costs by shifting generation from mid-merit and peak load power plants to base-load generators with lower operational costs. Secondly, it reduces fixed costs by replacing GT generators as a provider of capacity when needed (see Fig. 14).

4.5. Effect of interconnection capacity and electricity storage

Interconnection capacities and CAES electricity storage capacities are simultaneously adjusted to explore their impact (Fig. 15). Higher interconnection capacities decrease overall system costs, because power from intermittent-RES generators in one region can displace more fossil generation in regions with less intermittent-RES capacity (Germany & Benelux, Italy & Alpine countries). Also, base load power can run with higher capacity factors, which decreases operational costs. However, the costs of the interconnectors themselves add to the overall system costs. The least-cost deployment of interconnection capacity ranges from the current capacity (37 GW) for the 40% RES scenario, to the "low" case (123 GW) for the 60% and 80% RES scenarios.

To analyze the effect of extra storage on the system, extra CAES capacity is added exogenously to the 39 GW of PHS that is already present. CAES is deployed because it has the lowest LCOE (Fig. 9). Even though it reduces the installed capacities of NGCC-CCS and GT (by around 56 GW in the 95 GW CAES case), adding CAES capacity increases total system costs. The main reasons are the investment and charging costs of storage, which are too high in the current situation. This is depicted in Fig. 9, where it can be seen that storage does not have the lowest LCOE at typical charging costs.

A further reduction in investment costs of CAES is needed to obtain a competitive LCOE and thus the potential to reduce total system costs. A further investment cost reduction of >3% (5 GW CAES addition in the 80% RES scenario) to >6% (95 GW CAES addition in the 40% RES scenario) is needed on top of the 40% investment cost reduction that is included due to learning.

One of the benefits of storage, its ability to reduce curtailment, is limited because of the low share of intermittent-RES curtailment, and the technical restrictions of storage. One such restriction is its reservoir size, which is 8 kW h per kW output capacity. Increased storage capacity can further reduce curtailment, but will

[10] Small differences in CO_2 emissions exist between the scenarios. These are caused by our modeling approach, in which CO_2 emission caps are defined for the PLEXOS LT-plan, which translate to CO_2 prices that are used in the PLEXOS MT and ST schedules. Still, all specific emissions are much lower than the average specific CO_2 emissions of the EU27 in 1990 of 390 gCO_2/kW h [23].

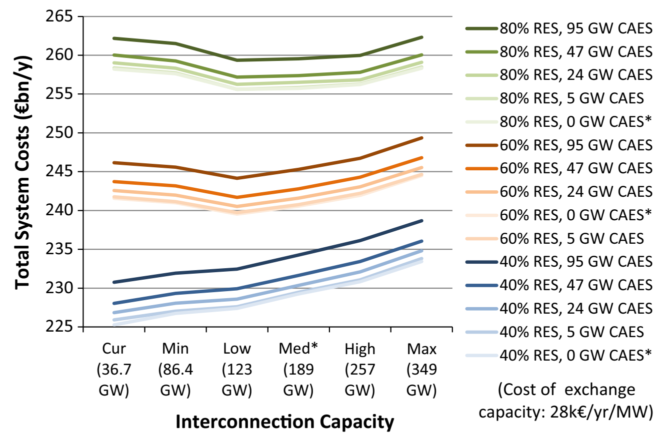

Fig. 15. Effect of interconnection capacity and electricity storage. * denotes the core scenarios.

increase storage investment costs. Higher curtailment may benefit the business case of electricity storage.

PHS and DR-shift are alternative options that are already included in the core scenarios. They can also shift power and load with higher combined charge/release efficiencies. In a hypothetical power system without both options, adding 5 GW of CAES (which equates to ~1% of peak load) reduces the total system costs by 0.1%. Thus, the existing presence of storage capacity may diminish the benefits of adding more CAES capacity.

4.6. Intermittent-RES integration costs

Two types of intermittent-RES integration costs have been quantified in this study: balancing and profile costs. Both are expressed as a function of the intermittent-RES penetration rather than the RES penetration.

The calculated balancing costs are shown in Table 8. They likely are an underestimation of the actual balancing costs because: (1) they are based on the shadow price of the model reserve-constraints, rather than the actual cost, and; (2) the model has perfect foresight of intermittent-RES generation, so suboptimal unit commitment will not occur. Also, other studies report higher costs (2–4 €/MW h for 0–40% intermittent-RES penetration) [34].

The calculated profile costs of the combined intermittent-RES generators are shown in Fig. 16 [34]. Please note that this study focuses on intermittent-RES penetrations of 22–59%. The cost-trend between 1% and 22% intermittent-RES penetration has been linearly interpolated, and may differ in reality. The calculated profile costs are in line with other studies, which show typical profile costs of −4 to 35 €/MW h for 0–40% intermittent-RES penetration. Three observations can be made:

1. Negative profile costs occur at 1% intermittent-RES penetration. The relatively expensive biothermal capacity is the cause of this, which is deployed with NGCC-CCS capacity to meet the CO_2 emission target at low RES penetration levels. Adding

Table 8
Calculated balancing costs of intermittent-RES.

Scenario	17% RES	40% RES	60% RES	80% RES
Intermittent-RES	0% iRES	22% iRES	41% iRES	59% iRES
Balancing costs (€/MW h_{iRES})	0.2	0.3	0.8	1

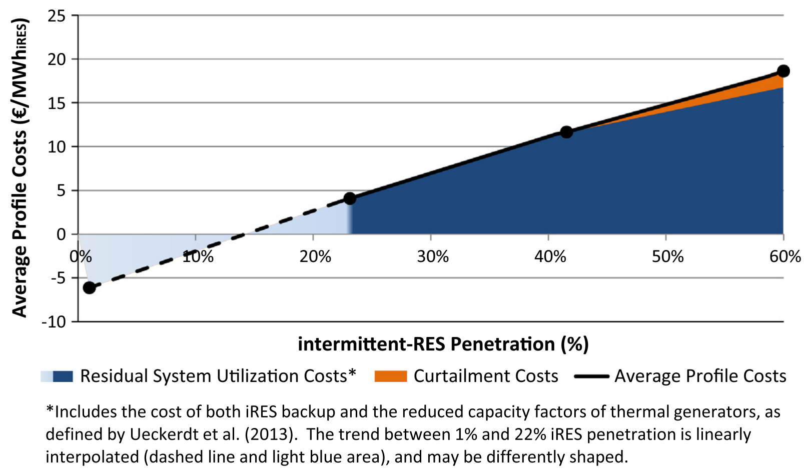

Fig. 16. Average intermittent-RES profile costs as a function of their penetration.

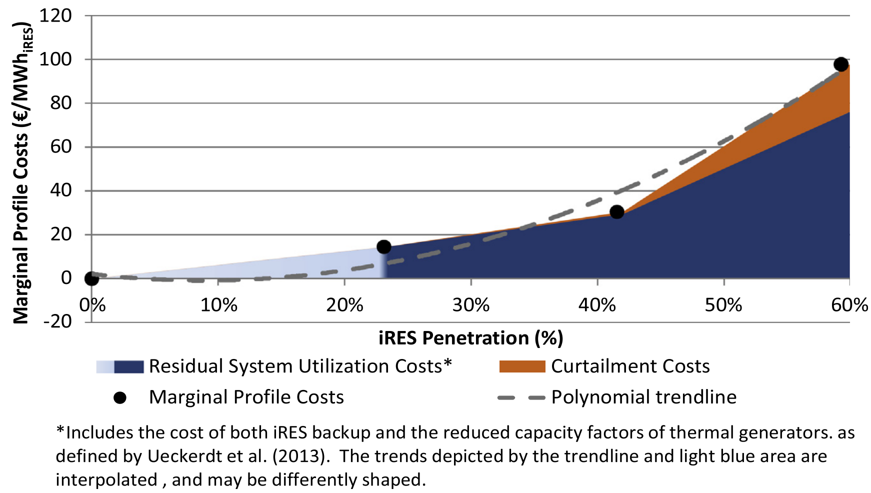

Fig. 17. Marginal intermittent-RES profile costs as a function of their penetration.

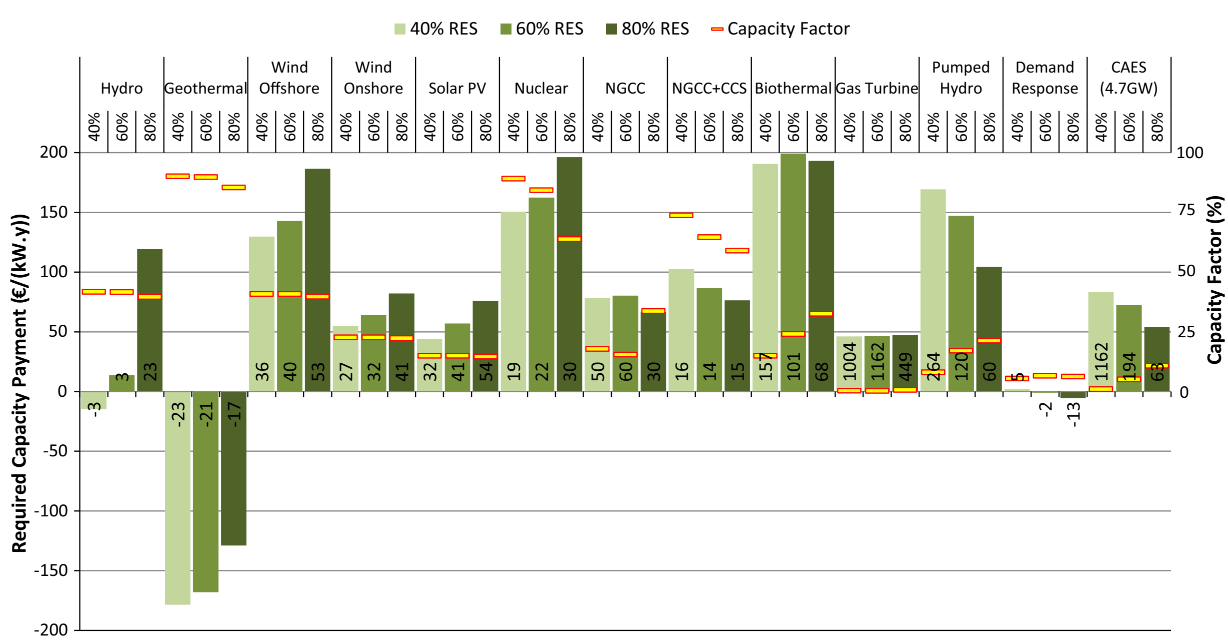

Fig. 18. Additional revenues required to reach break-even per generator type. Bars express the revenue gap as a capacity payment (€/kW/yr), while figures in the bars express the revenue gap as a premium on top of the electricity price (€/MW h).

Table 9
Variations explored in this sensitivity analysis.

Parameter	Variation	Reason
Demand response	0–200% of potential reported by [32]	Large uncertainty, so a large range
Fuel prices	60–120% of natural gas price 75% of biomass price	Variations change the merit order and thus power system operation
Emission cap	94% and 84% reduction of power sector CO_2 emissions compared to 1990	Less stringent emission caps reflect softer climate action
CAES deployment	CAES capacity equal to 0–20% of peak load	To explore the effect of electricity storage
Interconnection capacity	Current (37 GW) to extreme expansion (349 GW)	To explore the effect of interconnection capacity
Intermittent-RES investment costs	−10% and −20% of intermittent-RES investment cost, and low (500 €/kW) and high predictions (1095 €/kW) of solar PV investment cost	Intermittent-RES investment cost projections vary between sources [7,11,42]
No pumped hydro	No pumped hydro capacity	To exploring the effect of no PHS
Alternative demand profile	Adjusted profile with identical total electricity demand (2800 TW h/yr). See Appendix A for a description	To explore the effect of changing electricity demand patterns

12 GW (1%) intermittent-RES capacity also allows more NGCC-CCS capacity to be built, which altogether displaces 5 GW of biothermal capacity. This results in lower system costs and negative profile costs.

2. Profile costs increase with higher intermittent-RES penetration levels. This is due to two components of profile costs: (1) Higher intermittent-RES penetration progressively reduces the capacity factors of thermal power generators, which increases their fixed costs per MW h produced. (2) Higher intermittent-RES penetration leads to more intermittent-RES curtailment, which increases the profile cost per MW h produced.
3. There is a considerable difference between the average and marginal profile costs (Figs. 16 and 17). The *average* profile cost applies to a situation in which the profile costs of a certain intermittent-RES penetration level (e.g. 41%) are equally divided over all intermittent-RES capacity. When the intermittent-RES penetration increases (e.g. with 1–42%) the profile costs are again attributed to the total intermittent-RES capacity. The *marginal* integration costs applies to a situation in which an existing amount of intermittent-RES capacity is present in the system (e.g. 41%), and where the integration costs of adding more capacity are considered (e.g. 1% increase to 42% intermittent-RES). In this case, the cost-effect of this 1% increase is fully attributed to this additional 1% of increase in capacity. As the profile costs increase with higher intermittent-RES penetration, the marginal costs increase more rapidly than the average costs. It is therefore important to use the appropriate metric. The average intermittent-RES cost approach is suitable for scenario studies. The marginal approach is suitable for determining the impact of specific intermittent-RES capacity expansion plans in an existing situation.

4.7. Profitability of complementary technologies and other generators

The profitability of the complementary options as well as other generators is determined by comparing total revenues and costs. Within the framework of this study, which features an energy-only market system without revenues for ancillary services, almost all installations run at a loss. Curtailment and DR are the only profitable complementary options because they have low investment costs. Geothermal capacity also operates profitably due to its high capacity factor and relative low investment cost.

Fig. 18 shows that the capacity factors of almost all generators decrease with higher RES penetrations, leading to "profile" intermittent-RES integration costs. Only biothermal and pumped hydro capacity factors increase, because it is cheaper to dispatch the exogenously-defined biothermal capacity than to build additional gas-fired capacity. Moreover, pumped hydro can take advantage of temporal price differences.

The required additional revenues to obtain profitable investments increase with higher RES penetration due to decreasing capacity factors. This also applies to intermittent-RES, because intermittent-RES generators reduce their own revenues through the merit order effect. Overall, the required additional revenues in this study are significant: only 72% of total system costs are covered by revenues in the 40% RES scenario, and not more than 52% in the 80% RES scenario.

The revenue gap per generator has been quantified in two ways in Fig. 18. The bars depict the additional revenues that would be required per MW of capacity to make each generator break-even. In addition, the extra revenue per MW h that is required to make each generator break-even is given as a number. The extra revenue per MW h is driven by changes in the capacity factor and the average electricity price: it only decreases with higher RES penetration for peak load generators. Overall, these results show that the power systems simulated with the current energy-only market design in this study are not able to offer positive returns on investments.

4.8. Sensitivity analysis

Full model runs were performed with eight adjusted key parameters, see Table 9. The resulting total system costs and generation share per generator are shown in Figs. 19 and 20. The results of the sensitivity analysis highlight several key points:

- The total costs are largely determined by the exogenously defined 40%/60%/80% RES scenarios. Changes to specific single parameters do not affect to total results strongly.
- Lower investment costs of intermittent-RES lead to significantly lower total system costs. An overall intermittent-RES cost reduction of 32% compared to the base case value in Table 4 is the break-even point where the total systems costs of the 40% RES and 80% RES scenarios are equal.[11] System operation is not affected, and concerning the profile costs only the curtailment costs are reduced.
- A higher gas price (7.8 €/GJ) results in a shift of NGCC-CCS capacity and generation to PC-CCS generators. A lower gas price results in NGCC-CCS generation displacing biomass generation. If the gas price were to decrease in the 80% RES scenario due to lower demand, this scenario would remain the most expensive one.

[11] A 32% reduction in total costs includes a reduction in investment costs to 955 €/kW for onshore wind, 1809 €/kW for offshore wind and 478 €/kW for solar PV. If only investment costs of wind (both offshore and onshore) are reduced, a 50% reduction is required to equalize the total system costs of the 40% and 80% RES scenarios.

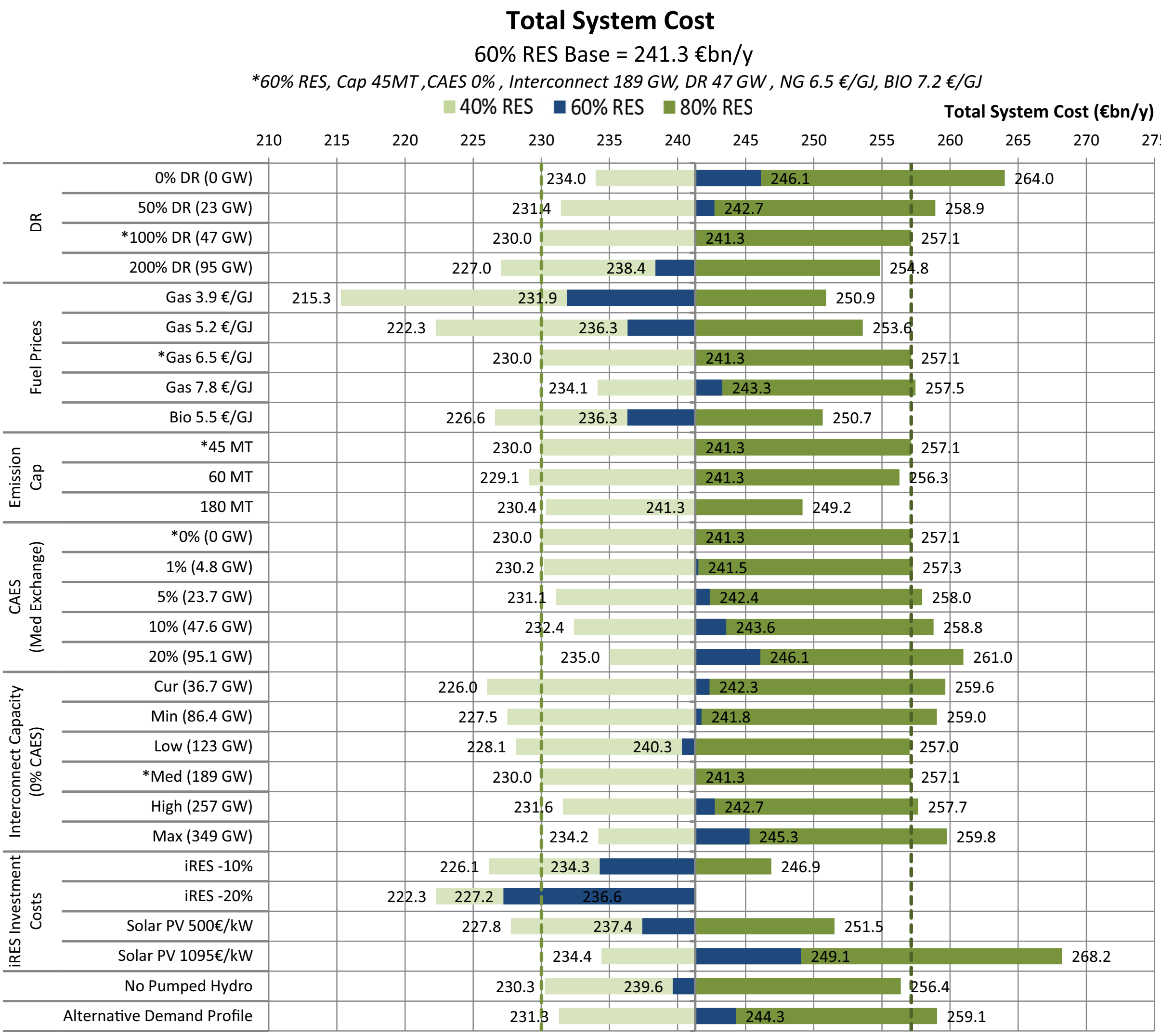

Fig. 19. Total annual system costs as simulated in the sensitivity runs. Bars drawn with reference to the 60% RES core scenario. Dashed bars represent the 40% RES (left) and 80% RES (right) core scenarios. An asterisk indicates the deployment level of options in all core scenarios (Table 1).

– Cheaper biomass (5.5 €/GJ) places biothermal generation earlier in merit order, before natural gas. This results in a shift of NGCC-CCS capacity and generation to biothermal generators.
– A more modest CO_2 cap (180 Mt/yr, which translates to specific emissions of 66 g/kW h) would result in increased NGCC capacity and power generation, at the expense of NGCC-CCS generators.

In addition, increased system flexibility, which can be realized with either DR, electricity storage or interconnectors, has three identical effects: (1) it leads to more base-load (geothermal and nuclear) generation (0–8% increase[12]); (2) it reduces installed GT capacity (0–40% decrease[13]) and GT generation (0–75% decrease[13]) and (3) it reduces curtailment of intermittent-RES generation (0–100% reduction in the 60% RES scenario[13], and 0–60% reduction in the 80% RES scenario).

5. Discussion

5.1. Limitations of the study

Our research scope includes most relevant elements that affect the integration of intermittent-RES in power systems. Still, some elements that could affect the results are not (fully) covered:

– The heat and transport sectors are not included. Close integration between these sectors and the electricity sector could increase flexibility at low costs though power-to-heat, heat storage and electricity storage in car batteries [53]. Moreover, conversion efficiencies can be improved with combined heat and power (CHP) plants [54].
– The study regions are relatively large, which leads to spatial smoothing and could underestimate the flexibility requirement. Transmission and distribution capacity within regions is not modeled, which leads to an underestimation of the costs of scenarios with increased interconnection capacity.

[12] Changes are compared to the 0% DR case for the 60% RES scenario.

[13] The CO_2 abatement costs give a better impression of the cost of CO_2 emission mitigation, because CO_2 prices are the same in all scenarios. This is the result of the same generator types being installed in the 40%, 60% and 80% RES scenarios. The deployment of RES is not driven by the CO_2 price, but by the scenarios. For the scenarios, the PLEXOS model calculates an internal CO_2 price of 70 €/tCO_2 during the optimization of fossil capacity, which is used for the MT and ST schedules. The most expensive abatement option (offshore wind) would require a CO_2 price of 126 €/tCO_2 to replace NGCC generation.

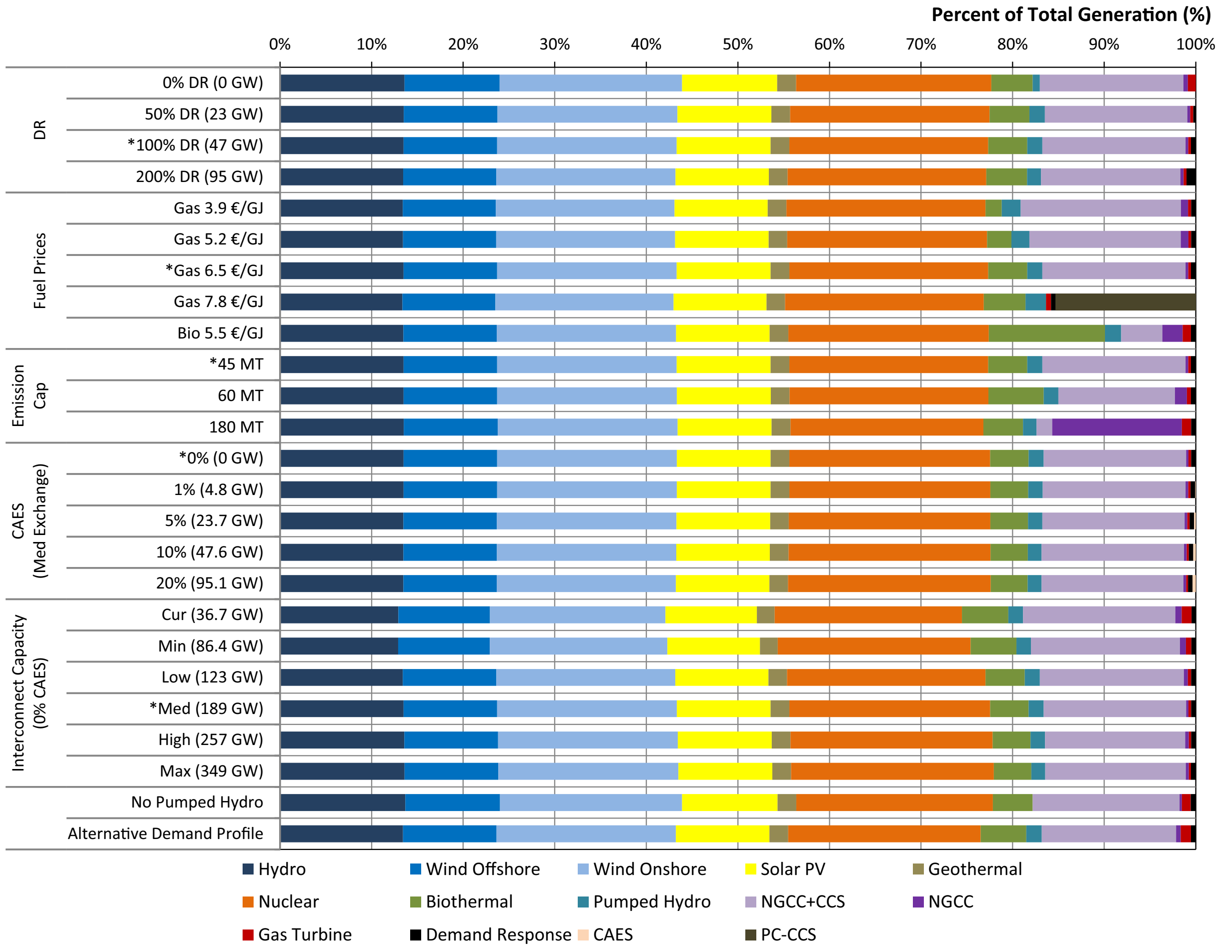

Fig. 20. Electricity generation per generator type as simulated in the sensitivity runs for the 60% RES core scenario.

- We only consider 12 types of power generators (Table 4). Plants firing or co-firing biomass combined with CCS are also promising options for low-carbon power systems. More diversity in peak generators (e.g. gas engines, CHPs) could affect the marginal electricity prices and profitability of the other generators.
- This study only considers snapshots of possible power systems in the year 2050. The transition from current to future power systems is indirectly included by basing the year 2050 electricity systems on existing scenario studies [3,6]. No legacy power plants are included in this study. Including legacy power plants may increase total system costs as they may not be part of the optimal, least-cost generation mix (i.e. high penetrations of intermittent-RES) [35].
- Capacity credits of intermittent-RES technologies are fixed. This assumption leads to a slight underestimation of the benefits of interconnections (interconnectors can increase the capacity credit by spatial smoothing), or a slight underestimation of the required OCGT-capacities in the 80% RES scenario compared to the 40% RES scenario (the relative capacity credits decrease with more intermittent-RES capacity).
- The DR potential and costs are uncertain. Limited information is available about the economic potential and associated costs, especially for DR by electric heating and electric vehicles. The actual economic potential and costs may therefore be different.
- No price premium for flexible natural gas supply is included in this analysis. Flexible gas supply results in lower utilization factors of the gas supply system and may require gas storage facilities which necessitate a price premium. The cost of any additional gas distribution, transmission and storage infrastructure has not been included.
- Only a single year of data (2013) has been used for load and intermittent-RES patterns.
- Perfect intermittent-RES forecasts are used in this study, which can underestimate the start-up and part-load efficiency costs of thermal generators. Other studies show that stochastic forecast may increase total system costs by 1% (at 35% intermittent-RES penetration [55]) to 2.5% (30% wind penetration [56]) compared to perfect forecasts.
- The natural gas price in 2050 is taken to be independent from the penetration rate of renewables. In practice the gas price may decrease when a high penetration rate of RES is achieved.

5.2. Consistency in study assumptions and outcomes

Two sets of assumptions do not appear to match well with the simulation outcomes.

- The deployment of electricity storage assumed for technological learning does not match the deployment of electricity storage resulting from the modeling. Rather, the cost reductions by technological learning[14] can be seen as "what if" situations to

[14] Investment cost reductions amount to 1.5% (PHS), 39% (CAES) and 65–70% (battery technologies).

assess the cost of electricity storage compared to other complementary options. The analysis shows that even with strong cost reductions, electricity storage does not reduce system costs.
– With the current modeling and scenario approach, investments in most power plant types are unjustified (see Section 4.7). New approaches or policy measures are required to make these systems economically viable (see Section 5.3).

5.3. Profitability of generators

The business cases of most power plant types are unsound within the modeling framework of this study (plausible scenarios, which are simulated with the current energy-only market design with given reliability and CO_2 emission reduction targets, and without remuneration for ancillary services).

Two potential reasons can be identified. First of all, intermittent-RES appear to drive down electricity price as well as the capacity factor of thermal power plants. Both negatively affect power plant profitability. Secondly, the electricity mix is partly exogenous, which introduces inefficiencies that would not be present in a fully endogenous, optimized mix. Still, not a single real-world electricity mix is completely cost-optimal due to political reasons and because the future is uncertain [57]. Please note that the marginal generator always experiences missing money in an energy-only system by definition [58].

Although the simulated investments may not make sense from a business perspective, they would result in lowest total system cost given the political decision to realize a low-carbon power system. Thus from a societal perspective, governments may want to increase generator revenues with additional market designs or policies. It is outside the scope of this study to analyze these designs or required policies in detail. Proposed mechanisms can e.g. remunerate power generation (improved energy only markets [59]; contracts for difference [60]; feed-in tariffs [61]; peak prices [62]); remunerate capacity (capacity mechanisms [58]; subsidies on investment [63]), and/or introduce markets that provide additional revenues (flexibility markets [64] and reserve markets [65]). In addition, investments in decentralized power generation can be stimulated with e.g. tax credits [66].

5.4. Comparison to literature

Comparing this work to other studies, two conclusions are shared: (1) Natural gas generators are an important source of flexible mid-merit and peak-load capacity in all studies [3,7,14,20,67–69]. (2) All studies conclude that demand response is a promising technology with many uncertainties [6,14,20,68].

There is no consensus about the cost-effectiveness of electricity storage. This study found that electricity storage is relatively expensive, which is supported by some studies [3,6,23,69]. However, other studies suggest electricity storage as a cost-effective option for high intermittent-RES penetrations in the United States (>40% iRES) [20], and Europe (60% iRES) [7], or for systems with 100% renewables [68]. Drivers for storage deployment may include (1) intermittent-RES penetration levels above about 65%; (2) the lower flexibility of potential legacy power plants, and (3) the geographical granularity of modeling.

Lastly, this study observes smaller benefits of increased interconnection capacity than other studies [3,20,67,68]. Three properties of this study could cause this:

1. Spatial smoothing occurs within the large study regions with internal copper plate transmission. This may reduce the need for power exchange between regions.
2. Interconnection capacity is exogenously defined, after which fossil capacity is optimized. Joint optimization of the two may improve interconnection benefits.
3. The effect of interconnection capacity on the capacity credit of intermittent-RES is not included.

6. Conclusion

This study compared five options that can improve the integration of intermittent-RES into future European low-carbon power systems in the year 2050. Three scenarios with 40%, 60% and 80% RES are simulated that meet predefined reliability (LOLP <0.2 d/yr) and CO_2 emission (96% emission reduction) targets. Results show that under base case assumptions:

- *Demand response* lowers total system costs by 2–3% compared to no DR deployment. There are uncertainties about the cost (costs of load shedding at 200–5000 €/MW h and load shifting at 2–100 €/kW are used) and its limited potential (47 GW is projected).
- *Natural gas fired generators* can provide large volumes of low-carbon electricity (NGCC-CCS) and relatively cheap capacity (GT). They replace the decreasing RES power generation between the 80% and 40% RES scenarios, reducing system costs by 12%. Natural gas fired generators are attractive due to their low investment costs and (inter-seasonal) flexibility capabilities.
- *Interconnection capacity* can increase capacity factors of base-load generators and thereby reduce system costs by 0–1% compared to the current capacity. The optimal interconnection deployment depends on the penetration of intermittent renewable generators. The current interconnection capacity is sufficient for the 40% RES scenario, while least-cost solutions in the 60% and 80% RES scenarios require 3–4 times the current interconnection capacity.
- *Curtailment of intermittent power generation* is cost-effective (2% cost reduction in the 80% RES scenario compared to no curtailment) and discards 0%, 0.1% and 2% of intermittent-RES power in the 40%, 60%, and 80% RES scenarios, respectively.
- *Electricity storage* is relatively expensive due to its high investment and charging costs, even after projected investment cost reductions from present day values of 40% (CAES) and 70% (batteries). Its deployment increases system costs by 0.1–3% compared to current storage capacity, so further cost-reductions are needed to make it a competitive technology.

This study shows that a 96% reduction in power sector CO_2 emissions in 2050 compared to 1990 can be reached with either higher shares of RES (80% RES) or a combination of natural gas fired generation with CCS, nuclear power and 40% RES. However, in our study total system costs increase in Western Europe with higher levels of renewables from 230 bn€/yr for 40% RES to 257 bn€/yr for 80% RES. The investment costs of intermittent-RES are a crucial element in this increase, as well as the projected fuel prices and the "profile costs", which are a key element of intermittent-RES integration costs. The profile costs reflect an intermittent-RES-driven reduction in capacity factors of thermal generators. Average profile costs increase from 4 €/MW h_{ires} for 40% RES penetration to 16 €/MW h_{ires} for 80% penetration.

At the same time, higher shares of RES lead to lower average electricity prices. Prices decrease from 57 €/MW h at 40% RES penetration to 47 €/WM h at 80% RES penetration. This increases the "revenue gap" problem in an energy only market for both complementary options and other generators from on average 23 €/MW h

(40% RES) to 43 €/MW h (80% RES). The only complementary options that make a profit are curtailment and demand response.

In our study the difference in total system costs between the 40% and 80% RES scenarios is 12%, so other reasons (e.g. geopolitical, sustainability and social perception considerations) may also drive decisions about future energy mixes. Whichever low-carbon energy mix is envisioned, demand response, intermittent-RES curtailment, natural-gas fired generation (with CCS), and interconnection capacity may lower total system costs. However, additional market designs or policies may be required to improve the business cases of complementary options as well as other generators in low-carbon power systems.

Recommendations for future research:

- Almost all simulated power plant business cases are unsound. Investigate how alternative market designs or policies can improve these business cases. These may include policies like improved energy only markets, capacity mechanisms and contracts for difference, as well as remunerations for providing flexibility and/or ancillary services.
- Demand response is a promising technology, but its future potential and costs need to be better quantified.
- Include the heating and transport sectors, as these can provide (potentially low-cost) flexibility to the electricity sector.
- Evaluate the potential of other biomass-fired options (e.g. co-firing with coal with and without CCS) and the potential of CO_2-negative options (e.g. biomass with CCS).
- Include more detailed gas system modelling – flexible production, gas storage, and distribution- to quantify the costs of more variable consumption.

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Appendix A. Projected load patterns

Load patterns are based on the historical load patterns per country of 2013, as reported by ENTSO-E [41]. Load increases by 0.25% per year to 2800 TW h in 2050, based on the IEA ETP'14 projections [6]. Realizing such a limited growth will require significant improvements in energy efficiency. A summary of electricity demand characteristics is provided in Table 10.

The alternative demand pattern is based on a master thesis [70]. It accounts for projected efficiency developments per sector (industry, transport, agriculture and energy sectors) and per end-use demand (within the residential and service sectors). Moreover, increased electrification of transport (to 23% of the passenger vehicle fleet) and heating (to 27–72% of residential and 15–58% of service sector heat demand, depending on the region) are included. The regional patterns were lastly scaled to the annual load as depicted in Table 10 so that any changes in total system cost are only caused by the changed demand pattern.

Appendix B. Projected intermittent-RES generation patterns

Generation patterns for wind and solar PV power were calculated based on meteorological observations for the year 2013. This year was chosen because: (1) this year is representative in terms of wind and solar PV generation (2) the availability of both meteorological time series and actual INTERMITTENT-RES generation data to validate the calculated time series; (3) this year is the most recent full year available, and captures recent developments.

B.1. Wind electricity generation pattern

Wind electricity generation is based on surface synoptic observations (SYNOP) reports, which are automated weather reports that report wind speeds at an hourly interval (some stations report every three hours). Wind speed reports were collected for 1498 locations across Western Europe [71,72], and were corrected with the following steps:

(1) The measurements are corrected from a hub-height of 10 m to one of 100 m, checked for >70% data availability per station, and unrealistic data points are omitted. Also, stations are categorized according to their location (onshore, offshore or combination of the two).
(2) The hourly electricity generation is calculated for each weather station with aggregated future wind power generation curves [73]. These provide projections of the technical performance of future wind power farms. The curves are specified for offshore and onshore turbines.
(3) We select the most attractive locations for wind turbines: the locations with the lowest capacity factors are omitted by setting a threshold for the minimum average wind speed at 10 m height. Average onshore and offshore capacity factors before curtailment of 24% and 41% are projected for 2050, based on extrapolated WEO2013 values [74]. On average, 55% of the least windy sites are omitted (±20%).

Table 10
Summary of electricity demand per region in 2050.

	Annual load (TW h)	Peak load (GW)	Min load (GW)	Average load (GW)
Germany & Benelux	737	113	50	84
Scandinavia	334	63	22	38
British Isles	377	67	23	43
France	547	102	33	62
Iberian peninsula	326	52	6	37
Italy and Alpine states	478	79	33	55

Table 11
Comparison of historical and calculated wind generation patterns for the year 2013.

	Germany + Belgium historical[c] (%)	Germany & Benelux calculated (%)	United Kingdom historical (%)	British Isles calculated (%)	France historical (%)	France calculated (%)
Correlation	85		70		86	
Average step change[a]	0.022	0.023	0.026	0.023	0.025	0.021
Standard deviation[b]	19	21	22	15	20	18
capacity factor[b]	19	29	32	33	25	26

[a] Absolute values are taken. Change can be in upward or downward direction, and are expressed as a percentage of the highest generation level in the year.
[b] The standard deviation and capacity factor are expressed as a percentage of the highest generation level in the year to make a fair comparison. The actual capacity factor will be lower (about 90% or reported value), because generation never equals 100% of the nameplate capacity.
[c] Consists of only historical generation in Germany and Belgium; The Netherlands were not available (but are included in the simulated data series).

(4) We apply a smoothing step per country, where the rolling average of each hour and its two adjacent hours is calculated. This step dampens the fluctuations in power output, so that these are better in line with the fluctuations observed in wind electricity generation today.

The simulated electricity generation by onshore wind turbines per country is next compared to the historical wind generation for three regions of the year 2013[15] (Table 11). As can be seen in the table below, the correlation between the historical and simulated patterns is good but not perfect. This is due to: (1) the larger range of sites that are considered in our analysis; (2) the simplified approach, in which 10-m measurements were converted to a 100-m height with a fixed roughness distance; and (3) the difference in study regions and regions for historical series. The average step change and standard deviation match well between the historical patterns and simulated patterns. The only major difference is the difference in capacity factors for Germany & Benelux in that the historical factor is much lower than the simulated capacity factor. The cause is unclear: only 0.33% of renewables were curtailed in 2013, so curtailment is not an explanation. Other explanations include a less favorable wind regime then assumed, or the fact that Dutch generation data were unavailable for the real generation pattern.

B.2. Solar PV electricity generation patterns

Solar PV generation data are based on the HelioClim-4 database, which provides historical solar insolation time-series with a time step of 15 min whilst accounting for weather conditions (i.e. clouds) [75,76]. Time series were collected for 80 sites across Europe, which were selected with the assumption that most capacity will likely be installed in or near urban areas (Fig. 21).

The insolation is a direct proxy of electricity generation: power generation in a given hour is equal to the share of insolation in that hour as part of annual insolation, multiplied by the annual power generation. Based on historical solar PV power generation patterns of Germany and France, it was established that a ratio of 0.85:1 (diffuse insolation:direct insolation) results in the best correlation between modeled and actual power generation power generation patterns (r^2 >98%, difference in σ is <±3%). This close match could be further improved by accounting for the angle of the sun and the temperature of the panel, but this is not included due to research constraints.

[15] Historical production patterns were obtained from http://www.pfbach.dk/firma_pfb/time_series/ts.php.

Fig. 21. locations from which solar irradiation time series were collected.

Electricity generation in 2050 is calibrated based on the extrapolated average solar PV capacity factor of 16% across the European Union [74]. The average capacity factor accounts for the distribution of the solar PV generator capacity across the six regions, and the average generation profiles of these regions. This results in the average capacity factors shown in Table 12.

B.3. Capacity credit of intermittent-RES

Capacity credits for wind and solar PV are determined with a method supplied by the IEA [30]. Capacity credits for onshore wind are 5–17%, and for offshore wind 9–24% between the six regions. The lowest credits are found for the regions with most wind power. Capacity credits for solar PV are 0% in every region.

Because only a single year of intermittent-RES and load patterns is available, actual capacity credit values might be lower. We therefore use a capacity credit of 5% for both onshore and offshore wind, an 0% for solar PV.

Table 12
Calculated capacity factors for solar PV electricity generation in 2050.

Region	Germany & Benelux (%)	British Isles (%)	France (%)	Scandinavia (%)	Iberian Peninsula (%)	Italy & Alpine states (%)
Capacity factor	13	12	15	11	21	17

Appendix C. Projected power plant flexibility parameters

The flexibility of power plants is based on a publication of Brouwer et al. [11]. Data on the current and future flexibility of power plants were collected from equipment manufacturers, reports and scientific articles, and confirmed with five experts (Table 13). The addition of a CO_2 capture unit is not expected to affect the flexibility parameters of the base power plant, so the flexibility of PC and NGCC plants with and without CCS are the same [11].

We use the projected flexibility of power plants for the year 2030 as input data for our 2050 analysis, as this flexibility is already significantly better than current parameters, and because it is hard to project long-term developments.

Ramp rates are expressed per minute, but these rates cannot be sustained for 60 min. We use the 'triangular ramping rule', which specifies that the hourly ramp rate of nuclear-, PC- and NGCC power plants is 33% of the minute-ramp rate.

The flexibility of thermal generators that run on 100% biomass is assumed to be equal to that of PC-CCS plants in line with other studies [7,77]. Hydropower and geothermal generators have ramp rates of 4.1% and 0.75%, respectively, and a minimum load of 20%.

C.1. Power plant part-load efficiencies

State-of-the-art part-load efficiencies are also adopted from Brouwer et al. [11]. Curves are described by the function $y = a + bx + cx^2$, where x is the load of the power plant as a percentage of max load. The relative efficiency curves are shown in Fig. 22. We assume that the part-load efficiency of biomass-fired power plants is the same as PC power plants, as the steam cycle equipment is similar [44].

C.2. Power plant outages

The forced (unplanned) outage rate of power plants is on average 4% [79,80]. Once unavailable, the mean time to repair is modeled to be 50 h [81,82]. In addition, plants are offline for planned maintenance 5% of the time.

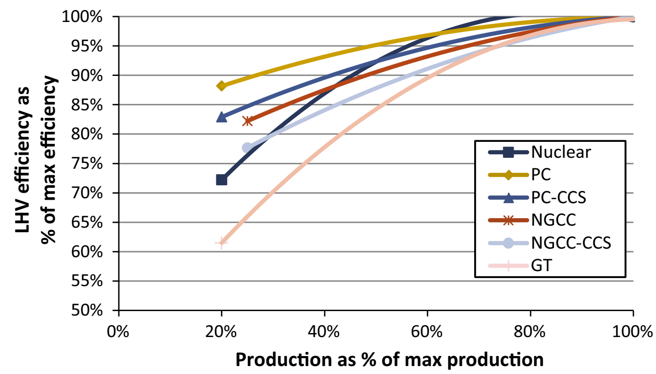

Fig. 22. Relative part-load efficiency of power plant as percentage of full-load efficiency.

Appendix D. Projected balancing reserve requirements

Forecast errors in expected load and intermittent-RES generation, as well as unforeseen events (e.g. power plants tripping) threaten the balance between supply and demand. Therefore, power systems need balancing reserves that can be quickly activated.

D.1. Types of balancing reserves

In this study we account for three types of reserves:

- Spinning up reserves: available within 5 min, with a 1-h ahead forecast.
- Spinning down reserves: available within 5 min, with a 1-h ahead forecast.
- Standing up reserves: available within 60 min with a 12-h (wind) or 24-h ahead (solar PV) forecast.

D.2. Determine the reserve requirement of intermittent-RES

D.2.1. Approach in modeling studies

The reserve requirement of intermittent-RES is set by the difference between the forecasted power generation and the actual

Table 13
Flexibility parameters of power plants per technology [11].

	Technology			Start-up time (hours)			Start-up cost (€$_{2012}$/MW$_{installed}$ per start)[c]		
	Decade of commissioning[a]	Minimum load (% of max capacity)	Ramp rate (% of max capacity/minute)	Hot start[b]	Warm start[b]	Cold start[b]	Hot start[b]	Warm start[b]	Cold start[b]
Nuclear[d]	2030	20 ± 5	5 ± 2	3 ± 1	8 ± 2	20 ± 5	39 ± 12	46 ± 14	75 ± 23
PC(-CCS)	2030	20 ± 10	6 ± 2	2 ± ½	4 ± 1	8 ± 2	39 ± 12	46 ± 14	75 ± 23
NGCC (-CCS)	2030	25 ± 10	9 ± 2	1 ± ¼	2 ± ½	3 ± 1	27 ± 11	39 ± 20	57 ± 29
OCGT	2030	20 ± 10	20 ± 5	¼	¼	¼	13 ± 6	16 ± 8	23 ± 12

[a] Figures depict the typical state-of-the-art performance per decade.
[b] Starts are classified based on the elapsed time since shutdown. We distinguish hot (offline for <8 h), warm (offline for 8–48 h) and cold (offline for >48 h) starts.
[c] Start-up costs include fuel, maintenance, auxiliary power, depreciation and forced outage costs. CO_2 credit costs are not included.
[d] Limited nuclear power plant start-up costs have been found in the literature. Start-up costs equal to those of PC power plants are assumed based on [78].

power generation in every hour. Because the actual difference is not known for single hours, the reserve requirement is defined as (multiple) general rule(s), which are based on historical time series. There is no universal method to determine the effect of intermittent-RES on reserve sizes. Over 20 studies have determined the reserve size with a range of methods [10,83].

Typically, advanced intermittent-RES reserve sizing takes 3 steps:

(1) forecasts of intermittent-RES power generation are generated with advanced forecast tools, such as weather models, satellite measurements and on-site measurements;
(2) the forecasted power generation in every hour is compared to the actual generation; (3) the reserves are sized such that they cover a predefined share of all forecast errors (e.g. 95%).

Advanced sizing methods can meet reliability requirements with smaller average reserve sizes, by using advanced forecasting tools, by determining the required size per hour (instead of using a fixed size), and/or by calculating a combined reserve size for the intermittent-RES and load forecast error, as well as the risk of power plant outages [10,84].

In this study, we use a similar three step approach.

(1) Firstly, we generate persistence forecast of intermittent-RES power generation based on the actual intermittent-RES power generation time series from Appendix B, due to unavailability of advanced forecasting techniques. Persistence forecasts are a basic forecasting technique that assumes that the weather conditions will remain constant over time: the wind power generation in $t + 1$ is the same as in moment t. At short timescales of up to an hour, this approach gives reasonably accurate predictions, but its accuracy is significantly worse at longer timescales of up to 24 h.
(2) In the second step, we compare the forecasts of each hour to the actual power generation. Next, we compare the persistence forecast approach to more advanced forecasting techniques that are currently used. Persistence forecasts will perform worse compared to these advanced techniques, so we determine a correction factor by which the persistence forecast error of every hour is reduced. We compare the quality of our persistence forecasts to forecasts for Germany and Spain, because data is only available for these two areas.
(3) The result of step 2 is a collection of forecasts errors. We can determine a single fixed reserve size for the whole year that covers 95% of all forecast errors. This approach will overestimate the required amount of reserves for most hours, however. Instead, we make the reserve size dynamic, based on parameters that are known at the moment the forecast is made and which affect the reserve size. We divide the year in tranches, based on the time of day, the season and/or the power output at the moment of the prediction, and determine the reserve size need to cover 95% of the forecast errors within each tranche [85].

D.2.2. Solar PV reserve size determination

(1) Based on the hourly solar insolation patterns and the clear sky insolation, persistence forecasts were made with the method described by [85,86]. Two forecasts were made for each of the six aggregated regions:
   - 1 h-ahead forecasts to determine the size of short-term reserves (i.e. spinning reserves with activation times of <5 min),
   - 24 h-ahead forecasts to determine the size of longer-term reserves (i.e. reserves with an activation time of <60 min).
(2) We compared the standard deviation (σ) and Mean Absolute Error (MAE) of the forecast error of our persistence approach to those of the historical predictions, and two sets of simulated predictions for Germany (Table 14) and Spain (Table 15). The 1 h forecast error, which is used for spinning

Table 14
Comparison of the accuracy of solar PV forecasts for Germany for a single year.

Type of forecast	Persistence	Persistence	Weather model	Persistence	Weather model
Description	Made as part of this study	Made as part of this study	Official historical forecasts	Analysis of prediction models	Analysis of prediction models
Forecast horizon	1 h ahead	24 h ahead	12 h ahead	24 h ahead	24 h ahead
σ (% of average annual generation)	16%	64%	52%	64%	40%
Mean Absolute Error (% of average annual generation)	11%	40%	38%	41%	26%
Year, type and source of time series	2013; insolation and max insolation [75]	2013; insolation and max insolation [75]	2013; reserve sizes. [88]	2006–2007[a] Time series not published	2006–2007[a] Time series not published
Source of method	[85,86]	[85,86]	Forecast by market parties/TSOs	[86]	[86]

[a] These forecasts were made based on historical weather data of 2006–2007 by Perez et al., using state-of-the-art forecasting models in 2012.

Table 15
Comparison of the accuracy of solar PV forecasts for Spain for a single year.

Type of forecast	Persistence	Persistence	Persistence	Weather model
Description	Made as part of this study	Made as part of this study	Analysis of prediction models	Analysis of prediction models
Forecast horizon	1 h ahead	Day ahead	Day ahead	Day ahead
Root Mean Square Error (% of average annual generation)	15%	40%	35%	22%
Mean Absolute Error (% of average annual generation)	10%	25%	19%	13%
Year, type and source of time series	2013; insolation and max insolation [75]	2013; insolation and max insolation [75]	2006–2007[a] Time series not published	2006–2007[a] Time series not published
Source of method	[85,86]	[85,86]	[86]	[86]

[a] These forecasts were made based on historical weather data of 2006–2007 by Perez et al., using state-of-the-art forecasting models in 2012.

Table 16
Average annual reserve size and max reserve size as percentage of total installed solar PV capacity

Reserve type	Type	Direction	Germany & Benelux (%)	British Isles (%)	France (%)	Scandinavia (%)	Iberian Peninsula (%)	Italy & Alpine States (%)	Average for total area (%)
Spinning	Avg	Up	2	2	2	3	3	2	2
Spinning	Avg	Down	−2	−2	−3	−3	−3	−2	−2
Standing	Avg	Up	5	5	6	4	6	5	5
Spinning	Max	Up	7	7	7	9	10	6	
Spinning	Max	Down	−11	−11	−8	−11	−8	−7	
Standing	Max	Up	26	21	25	21	20	17	

reserves, is assumed to be the same as more advanced approaches [87]. The 24 h forecast error, which is used for standing reserves, is larger for our persistence approach than for the advanced weather model approaches. In order to not overestimate the required reserve size, we reduce the 24 h-forecast errors of our persistence forecast by 35% (1 – [best_available MAE/persistence MAE], based on the data from Perez et al. in Tables 14 and 15).

(3) To reduce the reserve size, we use a dynamic reserve sizing approach with 45 tranches. This approach determines the reserve size based on: (1) period of the day [3 levels: morning, afternoon, evening], (2) the percentage of insolation as part of the clear sky insolation [5 levels], (3) the seasons [3 levels: 3-month blocks around winter/summer solstice, and remaining time]. This approach is based on Lew et al. [85], who considered the time of day and the share of insolation. We used fewer levels [Lew et al. use 10 per characteristic] for each characteristic, because our dataset has a coarser resolution (1 h vs. 5 min).

Dynamic reserve sizing leads to smaller reserves compared to a single annual reserve size. Distinguishing between 45 tranches reduced reserve sizes on average by 12% (hour ahead), and 22% (day ahead). The average reserve size during hours of daylight is shown in Table 16.

D.2.3. Wind reserve size determination

(1) We create persistence forecasts in the same way as for solar PV.
(2) We compared our calculated wind forecast errors to historical wind forecast errors, as shown in Tables 17 and 18. We observed that the persistence forecasts for short timeframes are reasonably accurate. At longer timeframes, historical forecasts are more accurate because of the superior performance of weather prediction models [89]. We reduce the 1 h ahead persistence forecast errors by 33%, and the 12 h and 24 h ahead persistence forecast errors by 66%. This way they are better in line with historical errors and general trends [87].
(3) Next, we dynamically determine reserve sizes, based on 36 tranches: we distinguish 6 daily periods, and 6 load levels. These tranches allow us to categorize the different reserve sizes, and reduce their size on average by 14%/20% (up/down) for 1 h forecasts, and 16%/35% (up/down) for 12 h forecasts. The average reserve sizes for all regions are shown in Table 19.

Table 17
Comparison of the accuracy of wind forecasts for Germany for a single year.

Type of forecast	Persistence	Persistence	Persistence	Weather model	Historical	Historical
Description	Made as part of this study	Made as part of this study	Made as part of this study	Historical forecasts	Analysis of historical forecasts	Analysis of historical forecasts
Forecast horizon	1 h ahead	12 h ahead	24 h ahead	12 h ahead	1 h ahead	24 h ahead
σ (% of total installed wind capacity)	1.9%	15%	16%	4%	1.2%	5%
Mean Absolute Error (% of total installed wind capacity)	1.4%	10%	12%	3%		
Year, type and source of time series	2013; wind speed time series; [71,72]	2013; wind speed time series; [71,72]	2013; wind speed time series; [71,72]	2013; reserve size; [88]	2010; time series not published	2010; time series not published
Source of forecast method	[85,86]	[85,86]	[85,86]	Forecast by market parties/ TSOs	[90]	[90]

Table 18
Comparison of the accuracy of wind forecasts for Spain for a single year.

Type of forecast	Persistence	Persistence	Persistence	Historical	Historical
Forecast horizon	1 h ahead	12 h ahead	24 h ahead	1 h ahead	24 h ahead
Description	Made as part of this study	Made as part of this study	Made as part of this study	Analysis of historical forecasts	Analysis of historical forecasts
σ (% of total installed wind capacity)	3.7%	18%	15%	1.3%	5%
Mean Absolute Error (% of total installed wind capacity)	2.7%	15%	11%		
Year, type and source of time series	2013; wind speed time series; [71,72]	2013; wind speed time series; [71,72]	2013; wind speed time series; [71,72]	2010; time series not published	2010; time series not published
Source of method	[85,86]	[85,86]	[85,86]	[90]	[90]

Table 19
Average annual reserve size as percentage of total installed wind capacity.

Reserve type	Type	Direction	Germany & Benelux (%)	British Isles (%)	France (%)	Scandinavia (%)	Iberian Peninsula (%)	Italy & Alpine States (%)	Average for total area (%)
Spinning	Avg	Up	2	2	2	2	4	3	3
Spinning	Avg	Down	−2	−2	−2	−2	−4	−3	−2
Standing	Avg	Up	8	6	7	6	11	6	7
Spinning	Max	Up	4	3	4	3	9	4	
Spinning	Max	Down	−4	−4	−4	−3	−10	−4	
Standing	Max	Up	11	12	11	11	17	10	

D.2.4. Calculating the combined reserve size

We calculate the total reserve size for each hour for each of the six regions based on the total of the following four components:

(1) The calculated solar PV reserve sizes.
(2) The calculated wind power reserve sizes.
(3) A 1% load forecast error, as used in the WWSIS-2 study [91], and typical for larger regions [84].
(4) An N-2 reliability criterion. This criterion defines that enough reserves must be available to balance unscheduled outages of the two largest power plants (N-2) in the system of 1500 MW each. 3000 MW of spinning and standing reserves are required across Europe, in line with current and proposed future regulations [92].

These four components are independent from each other, and are added triangularly as described by Lew [85]. 20% of reserve capacity is actually utilized, as calculated for intermittent-RES in this study, and confirmed by data for Germany [93].

Appendix E. Projected interconnection capacity

Interconnection capacity can increase the flexibility of the total system. Its deployment is exogenously defined in the model based on a literature review of interconnection scenarios for the year 2050 [3,7,46,94–96] and the current installed capacity. Significant capacity increases are projected from the 37 GW that is installed in 2015 [45]. Two studies are selected that optimized installed interconnection capacities for multiple penetration levels of intermittent-RES [3,46], from which we formulate five additional interconnection cases, as shown in Table 20 and Fig. 4. An example of interconnection capacities between countries is shown in Table 21. Looking at France, the 'minimum' interconnection case is sufficient to meet the EU target of having interconnection capacities equal to 15% of installed generation capacity [97].

Investment costs of interconnectors are 28 k€/MW/yr, based on 50% alternating current, and 50% direct current cables with average lengths of 80 and 130 km respectively, all above-ground [14,47]. Interconnection capacity is expressed as net transfer capacity, without considering loop flows. It is assumed to be symmetrical between regions.

Appendix F. Projected demand response potential and cost

Demand Response (DR) can be used for four different goals. It can: (1) contribute to resource adequacy by reducing peak demand; (2) solve network constraints; (3) provide balancing reserves; and/or (4) provide consumers with access to real-time electricity prices [49]. In this study we only consider the contribution of DR to resource adequacy. By using DR capacity, the peak load of the power system can be reduced, which in turn reduces

Table 20
Interconnection cases used in this study.

Interconnection case name	Based on studies' RES penetration of	Per region the ... of both studies	Total capacity (GW)
Current	–	–	37
Minimum[a]	40%	Minimum	86
Low	40%	Average	123
Medium	60%	Average	189
High	80%	Average	257
Maximum[b]	80%	Maximum	349

[a] We first select the lowest projected capacity per region between the two studies [3,46]. We compare this to the current net transfer capacity [98], and select the highest of the two values. Overall, the sum of all interconnectors is rather low: ∼30% lower than the projected total capacity that is reported by either study [3,46]. This is therefore an extreme case.
[b] We first select the highest projected capacity per region between the two studies [3,46]. Overall, the sum of all interconnectors is rather high: 19% [3] and 58% [46] higher than the projected total capacity that is reported by either study [3,46]. This is therefore an extreme case.

Table 21
Net transfer interconnection capacity between regions in medium interconnection case.

Interconnection capacity in MW	British Isles	France	Germany & Benelux	Iberian Peninsula	Italy and Alpine States	Scandinavia
British Isles	–	12,788	4946	0	0	0[a]
France	12,788	–	19,910	27,389	13,149	0
Germany & Benelux	4946	19,910	–	0	6619	9764
Iberian Peninsula	0	27,389	0	–	0	0
Italy and Alpine States	0	13,149	6619	0	–	0
Scandinavia	0[a]	0	9764	0	0	–

[a] In the hight and maximum interconnection cases, a link between Scandinavia and the British Islands is included.

Table 22
Overview of demand response options considered in this study.

Sector	Process	DR measure	Max shift time (h)	Max load reduction duration (h)	Technical potential (GW_{DR})[a]	Utilized potential	Unit size (kW)	Average capacity factor[b] (%)	Investment cost (€/kW_{DR})	VOM cost (€/kW h_{DR})	FOM cost (€/kW_{DR})
Industry	Electrolytic metal production	Shed	∞	4	1.2	90%	–	100%	1	1000	–
Industry	Electric arc steel production	Shed	∞	4	4.3	90%	–	100%	1	2000	–
Industry	Chloralkali process	Shed	∞	4	1.3	90%	–	95%	1	100	–
Industry	Cement mills & miscellaneous[c]	Shed	∞	3	2.6	90%	–	80%	16	700	–
Industry	Paper production	Shed	∞	3	4.6	90%	–	90%	13	10	–
All	Shift 1 h load by 2 h[d]	Shift	2	1	16.5	33–90%	1[f]	50%	3	–	1
All	Shift 2h load by 2h[e]	Shift	2	2	6.3	33–90%	1[f]	50%	3	–	1
Tert/Res	Air conditioning	Shift	2	1	4.2	33–50%	2[g]	5%[h]	17	–	4
Tert/Res	Space and water heating	Shift	12	12	127.4	33–50%	1[f]	57%[i]	3	–	1
Residential	Washing machines & dryers	Shift	6	∞	9.0	33%	1	2%	100	–	26
Residential	Freezer/refrigerator	Shift	2	1	11.5	33%	0.1	40%	43	–	11
Source		[32]	[32]	[32]	[32]	[7]	[32]	[32]	[48,49]	[48]	[49]

[a] The total technical potential in the six regions considered in this study.
[b] This is the capacity factor of the appliances themselves, not of DR-capacity.
[c] Also includes calcium carbide production and air liquefaction.
[d] Consists of ventilation in industry, cooling in food retailing and commercial ventilation.
[e] Consists of cooling in industry, cold storages, cooling in hotels and restaurants, pumps in water supply and waste water treatment.
[f] Conservative assumption made in this study, which reflects that DR investment costs per appliance might be higher for appliances with a bigger electrical rating. Investment and FOM costs are insignificant compared to investments in residential DR and thermal generation capacity.
[g] Conservative estimate of unit size based on [99].
[h] Depends on the annual capacity factor of cooling equipment as specified by [32]. Ranges from 2% in Scandinavia to 7% in the Iberian Peninsula.
[i] Depends on the annual capacity factor of heating equipment as specified by [32]. Ranges from 47% in the Iberian Peninsula to 65% in Scandinavia.

the amount of installed generating capacity that is required to maintain system adequacy.

Overviews of the total technical European DR potential show that the residential sector has the largest potential, followed by the tertiary and industrial sectors (Table 22) [7,32]. The DR potential in the former two sectors consists of load shifting, where the operation of appliances is shifted backward or forward in time by means of price signals or smart grids. Industry mainly offers load shedding capabilities, where generation is reduced in order to reduce load in hours of high residual electricity demand.

We base the potential per country on an overview by Gils [32]. Load-shifting for heat generation is considered for present-day heat demand, while electrified transport is not included. To reduce complexity, we only account for differences in DR-potential between the seasons: winter, summer and spring/autumn are defined separately for air-conditioning and heat generation, where we assume that the potential is 25% in spring/autumn, and 100% of the potential reported by Gils in the season of highest demand (e.g. winter for heat generation), and 0% in the season with lowest demand.

The utilized potential varies per sector [7]. Industry is more cost-oriented and better organized, while individual households may value utility of their appliances over a financial incentive. The maximum deployment is based on projections for Germany in 2050: 90% of industry potential is deployed, 50% of tertiary sector potential, and 33% of residential sector potential [7].

Costs for industrial applications are based on [48], which defines investment and VOM costs. Costs for the residential sector are based on an investment cost per appliance of €1.7, and a standby electricity consumption of 1 W [49]. Based on the unit size and the capacity factor of the technology, the investment and Fixed Operation and Maintenance (FOM) costs per kW of available DR capacity are determined (e.g. a refrigerator consumes 350 kW h/y, so one unit can only contribute 350/8760 = 0.04 kW DR capacity. Investment costs are 1/0.04 ∗ 1.7 = €43/kW). The same approach is used for the tertiary sector, due to a lack of cost estimates for this sector. The calculated results show that the investment and FOM costs for this sector are lower than for households per kW, which is likely due to larger installations.

The 28 DR processes identified by Gils are aggregated into 12 categories by grouping processes with similar characteristics as shown in Table 22. The load shedding processes are defined as curtailable load in the PLEXOS model. The load shifting processes are defined as electricity storage facilities with constraints on the storage capacity, and the period during which the storage capacity can be utilized and their capacity factor as specified by [32].

Appendix G. Projected techno-economic specifications of electricity storage

G.1. Selection of storage technologies

The Energy Technology Perspectives 2014 report provides a screening of the LCOE of eight types of electricity storage technologies when providing six different kinds of storage services. Three of these services are relevant for this study: inter-seasonal arbitrage, daily price arbitrage and load following services. We have selected the five technologies that have the lowest LCOE for these applications, or the largest potential for cost reductions [6]. These include pumped hydro storage, adiabatic Compressed Air Energy Storage (CAES), as well as NaS, vanadium redox and Li-ion batteries. We consider adiabatic CAES because of its higher round-trip efficiency. Power-to-gas is not considered in this study because other studies indicate that it may not be attractive until 75–80% intermittent-RES penetration [22,52].

G.2. Present day techno-economic parameters

Technical parameters are taken from the ETP'14, as shown in Table 23. These values are in line with the other sources [50,51]. Present-day investment costs were compared between the Energy Technology Perspectives 2014, Ferreira et al. and Akhil et al. [6,50,51,69]. The Energy Technology Perspectives presents large ranges based on an elaborate literature review, while Ferreira and Akhil present smaller ranges based on vendor quotes [6,50,51].

Table 23
Technical performance of electricity storage technologies. Taken from [6].

Type	Technology readiness level TRL [100]	Response time	Round trip efficiency	Lifetime Years	Lifetime Cycles (×1000)
PHS	9	Sec–min	77 (70–85%)	40 (30–50)	35 (20–50)
CAES	8	Min	63 (50–75%)	35 (30–40)	17 (10–25)
NaS battery	7	Sec	80 (75–85%)	12 (10–15)	3.5 (3–5)
VRB	6	Sec	75 (65–85%)	12 (5–20)	>10
Li-ion battery	7	Sec	85 (80–90%)	12 (10–15)	7.5 (5–10)

Table 24
Overview of present-day electricity storage investment costs.

	Specific costs		Total costs of 8 h storage			
	This study €/kW	This study €/kW h	ETP'14 average €2012/kW	Ferreira average €2012/kW	Akhil average €2012/kW	This study €2012/kW
PHS	917	56	2690	1336	1357	1367
CAES[a]	872	39	1271	626	774	1182
NaS	1085	320	3643	4031	2868	3643
VRB	775	446	5503	4380	4767	4341
Li-ion	1705	1085	10,388	11,628	8020	10,388

[a] These costs refer to diabatic CAES. We simulate the deployment of adiabatic CAES, which has investment costs with are 1.5 times higher [101].

We compare the average cost as reported by ETP'14 to the average costs reported by Ferreira and Akhil. Two types of investment costs can be distinguished: the maximum electrical output of the installation in kW (which is dependent on e.g. the turbines for PHS, the electrodes for battery technologies and the rating of the base of system), and the storage capacity of the installation in kW h (which is dependent on e.g. the size of the reservoir for PHS and CAES, or the size of the battery). We base our values on the average cost reported by ETP'14, unless the vendor quotes of both other sources indicate that the ETP'14 costs are not representative of actual costs (Table 24). Adiabatic compressed air costs are 1.5 times higher than the reported diabatic investment costs [101].

G.3. Future costs

All storage technologies except for PHS are in an early phase of development with high costs but also a large potential for cost reductions. No worldwide scenarios are available for the deployment of storage technologies, but we anticipate that the total storage capacity (in MW) will be around 10% of the nameplate generation capacity of solar PV and wind power (around 480–710 GW of cumulative capacity, depending on the lifetime of the technology). This is based on:

– Projections of the IEA ETP'14, which reports that stationary storage capacity equals between 5% and 12% of intermittent-RES capacity in the 2DS scenario for four selected regions. A breakthrough scenario with aggressive cost reduction for electricity storage increases this ratio to up to 20% by 25–100%, while a scenario with more storage by electric vehicles reduces this ratio to 4–7% [6].
– A review by van den Broek et al., that showed that 9–22% of intermittent-RES nameplate capacity is needed as storage, or even 33% of its' capacity for a 100% intermittent-RES capacity scenario. The article uses 20% for their 'HIGH-REN' scenario with 70% intermittent-RES, and 10% for their 'BASE 450' scenario, which is based on the 2DS scenario from the IEA ETP'12 scenario [69].
– A study by Bussar et al. that found that 21% of intermittent-RES capacity is needed as storage in a 100% intermittent-RES power system [102].

It is unknown which types of storage will be deployed in the future, so a reduction in investment costs is projected for all five technologies. This reduction is caused by technological learning, and the assumption that half of the required electricity storage capacity will be supplied by each of the five technologies (240–355 GW of cumulative installed capacity per technology). This what-if analysis shows the future potential of each technology.

Capex progress ratios are 99% for PHS (relatively small due to a high share of civil construction costs, for which the learning potential is much smaller [74]) and 90% for the capex of battery technologies [69]. A middle-ground progress ratio of 94.5% is used for CAES. The OPEX does not improve through learning. We assume that the ratio kW/kW h of 1:8 remains constant over time as the IEA ETP'14 indicates that this ratio will remain profitable. Larger kW/kW h ratios might also be attractive for battery technologies, but they will require a smaller modeling time step. The costs of all storage technologies are shown in Table 5. These values are what-if values, if these penetrations of the specific storage technologies would be achieved.

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