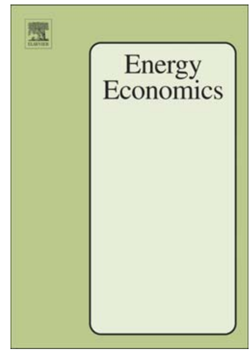
Accepted Manuscript



Application of a high-detail energy system model to derive power sector characteristics at high wind and solar shares

Yvonne Scholz, Hans Christian Gils, Robert Pietzcker

PII: S0140-9883(16)30168-2
DOI: doi: 10.1016/j.eneco.2016.06.021
Reference: ENEECO 3373

To appear in: *Energy Economics*

Received date: 13 October 2015
Revised date: 1 May 2016
Accepted date: 29 June 2016

Please cite this article as: Scholz, Yvonne, Gils, Hans Christian, Pietzcker, Robert, Application of a high-detail energy system model to derive power sector characteristics at high wind and solar shares, *Energy Economics* (2016), doi: 10.1016/j.eneco.2016.06.021

Application of a high-detail energy system model to derive power sector characteristics at high wind and solar shares

Yvonne Scholz[a*], Hans Christian Gils[a], Robert Pietzcker[b]

[a] Institute of Engineering Thermodynamics, German Aerospace Centre, Wankelstrasse 5, 70563 Stuttgart, Germany
[b] Potsdam Institute for Climate Impact Research, Germany

[*] Corresponding author. Email: yvonne.scholz@dlr.de, Tel.: +49 711 6862 296.

Abstract

Solar irradiation and wind speed vary with climatic, as well as seasonal and daily weather conditions. In order to represent these variable renewable energy (VRE) resources in specialized energy system models, high temporal and spatial resolution information on their availability is used. In contrast, Integrated Assessment Models (IAM), typically characterized by long term time scales and low temporal and spatial resolution, require aggregated information on VRE availability and balancing requirements at various levels of VRE penetration and mix. Parametric studies that provide such information typically regard solar energy synonymously with photovoltaic power generation. However, solar energy can also be harvested with Concentrating Solar Power (CSP) plants, which can be dispatchable if equipped with thermal storage. Accounting for this dispatchable use of the variable solar resource can change the balancing requirements at any solar energy penetration level. In this paper, we present an application of the high resolution energy system model REMix to a set of European supply scenarios with theoretical VRE shares ranging from 0-140%, three solar-to-wind ratios, with CSP included in the solar share. We evaluate balancing measures, curtailments and costs and compare the findings to previous results in which CSP is regarded a backup option among other dispatchable power plants. The results show that CSP potentials in Europe are widely exploited in most scenarios. System costs are found to be lowest for wind dominated systems or balanced mixes of wind and solar and for an overall VRE share between 40% for a low and 80% for a high scenario of the future CO_2 emission certificate price. The comparison with previous results shows that storage capacity is the only system variable that is significantly affected by allocating CSP to the VRE resources category. It is reduced by 24% on average across all VRE shares and proportions and by around 80% at most.

Key Words

Renewable energy, system integration, backup capacity, energy storage, curtailments, power transmission

Highlights

- We study VRE associated backup capacity and energy, storage and transmission use
- We cover a range of VRE shares from 0-140%, with three solar-to-wind ratios
- Capacity expansion and hourly dispatch for one year in a 16-region Europe is modelled
- In contrast to previous studies, CSP is included in the solar share
- System costs are minimized and we calculate LCOE and long term integration costs

Nomenclature

Symbol	Unit	Parameter
s_{VRE}	-	Overall supply share of Variable Renewable Energies
r_{S2W}	-	Overall ratio of solar to wind power generation
W_{PV}	kWh	Annual theoretical power generation of photovoltaic systems
W_{CSP}	kWh	Annual theoretical power generation of Concentrating Solar Power plants
W_{On}	kWh	Annual theoretical power generation of onshore wind turbines
W_{Off}	kWh	Annual theoretical power generation of offshore wind turbines

1 Introduction and theoretical background

Long-term energy system models and integrated assessment models (IAM) typically cover continents or the whole globe and are operated with few time steps per year or even per decade. From this follows that the temporarily fluctuating power output of variable renewable energy (VRE) sources cannot be comprehensively represented. Consequently, modellers must make assumptions about backup, transmission and storage or other balancing capacity and energy required to balance fluctuations that VRE add to the system. These assumptions become particularly important in assessments of future electricity system with high VRE shares (Luderer et al., 2014; Pietzcker et al., 2014). To develop realistic representations of VRE integration challenges for IAMs, it is important to base them on a large number of scenarios that explore a wide range of VRE shares with a detailed model. From such parametric studies, it is then possible to extract simplified dynamic representations that contain the key characteristics of how the power sector reacts to different levels of VRE generation (Sullivan et al., 2013; Pietzcker et al., 2016; Ueckerdt et al., 2016).

The required balancing capacity and energy depend on VRE penetration and mix. Most physical approaches to quantify required integration measures in Europe vary VRE mixes to minimize backup requirements without taking into account economic considerations: (Heide et al., 2010; Rasmussen et al., 2012; Rodriguez et al., 2014) identify VRE mixes between 20 and 45 % photovoltaic and 55 to 80% wind as optimal in terms of backup capacity and energy needs for a fully renewable European power supply. (Becker et al., 2014) find that transmission grid extensions shift the optimal mix from 30% photovoltaic and 70% wind to 20% photovoltaic and 80% wind power. Economic evaluations of integration measures minimize the total annual system costs and evaluate capacity expansion, dispatch or costs of system components (Schaber, Steinke, and Hamacher, 2012; Schaber, Steinke, Mühlich, et al., 2012; Rodriguez et al., 2015). In (Schaber, Steinke, Mühlich, et al., 2012), backup capacity, curtailments and grid extensions are systematically evaluated for different VRE shares and mixes in Europe in a wide parameter space. (Rodriguez et al., 2015) evaluate backup energy in addition. These studies disregard storage capacity expansion or regard it as included in the backup power generation. In (Scholz et al., 2016), we find that in an integrated European power system that allows for storage expansion, curtailments can be up to 15% lower than in the nationally dominated scenarios without storage expansion generated by (Schaber, Steinke, Mühlich, et al., 2012).

Apart from (Scholz et al., 2016), none of the abovementioned studies considers concentrating solar power (CSP). CSP plants with storage are dispatchable and can provide backup capacity if equipped with a conventional firing system (Trieb et al., 2012). In (Scholz et al., 2016), CSP is therefore considered non-variable. On the other hand, CSP uses the variable solar resource and for this reason is not distinguished from photovoltaics by some IAMs which only have one technology category 'solar'. However, if a share of solar power generation comes from CSP plants, fluctuations can be avoided from the outset and fluctuations from other VRE, i.e. photovoltaic and wind power generation, can be balanced, thus reducing the need for storage and additional backup. Since the levelised costs of photovoltaic power are lower and balancing requirements are still small today, CSP is not yet a profitable technology but its potential system benefits may make it more relevant in the coming decades. Since IAMs typically cover the full 21st century, they should consider CSP either explicitly as a separate technology or implicitly by modelling balancing measures that correspond to a cost efficient mix of both solar technologies.

This paper aims at a better understanding of the potential contribution of semi-dispatchable CSP to the balancing of VRE power generation in Europe. It is achieved by analysing the demand and provision of load balancing in the future European power supply. Using a high-resolution energy system model with linear optimization, we investigate the need for storage, transmission, backup capacity and backup energy, as well as the amount of curtailed energy and the system costs at different wind and solar power supply shares. In doing so, CSP is regarded a variable renewable energy source in order to find and deploy cost-minimal mixes of the solar resource using technologies CSP and PV.

The results can be used by IAMs that model CSP as a separate technology as well as IAMs that combine PV and CSP in the category 'solar'. In order to evaluate the sensitivity of the results to the emission costs, we consider three different CO_2 certificate price scenarios. The large number of scenarios and the detailed endogenous representation of the main flexibility options give us a unique position to calculate long-term integration costs for power systems optimally adapted to VRE and to assess the ability of CSP to provide backup power and energy. The presented REMix results are also used to evaluate newly developed representations of VRE integration challenges in a number of IAMs (Pietzcker et al., 2016).

This paper is structured as follows: section 2 provides an overview over methodology and data, summarizing the characteristics of the applied REMix model, presenting the parameterization and describing scenario assumptions. In section 3 we present the results, section 4 comprises discussion and conclusions.

2 Methodology and Data

In this section, we introduce the REMix model, as well as concept and input of the scenario assessment presented in this paper.

2.1 REMix Modelling Approach

REMix is a high spatial and temporal resolution energy system model developed at DLR to investigate cost-efficient integration of renewable energy into the energy system with a focus on power supply (Scholz, 2012; Stetter, 2014; Tena, 2014; Gils, 2015). It is used for validation and generation of supply scenarios. For validating scenarios, a given supply structure is pre-defined and its cost-minimal hourly dispatch is simulated by the model. For generating a scenario, least-cost power generation, transmission and other balancing capacities are dimensioned by the model and the hourly dispatch is calculated simultaneously.

REMix is composed of two main elements: the Energy Data Analysis Tool REMix-EnDAT on the one hand, and the Energy System Optimization Model REMix-OptiMo on the other. REMix-EnDAT processes energy related data such as hourly load data, temporally and spatially resolved meteorological data (e.g. wind speed, solar irradiance, temperature), spatial information (e.g. maps of land cover type, altitude, slope, country borders, power system infrastructure) and other. It calculates spatially and temporally resolved power and heat demand, as well as renewable energy potentials for user-defined regions. The results are used as input in REMix-OptiMo or other analyses that require spatially or temporally resolved energy data.

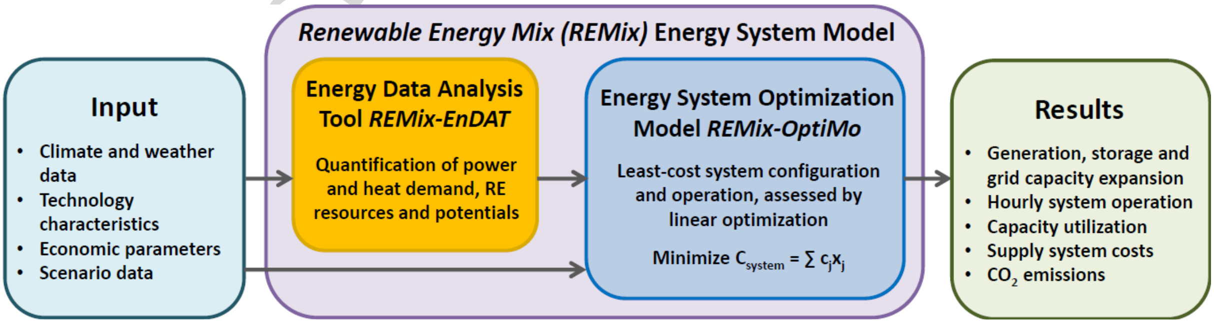


Figure 1: REMix model components and structure.

REMix-OptiMo considers hourly power generation restrictions for a whole year aggregated on user defined regions. The objective function is to minimize overall system costs, i.e. the sum of annuities of installed capacities, variable costs, fuel costs and emission costs.

Objective function and system constraints are formulated as linear, deterministic equations or inequalities. Given the high temporal resolution, linear modelling is necessary to keep running times as low as possible. The main constraint is the power balance which ensures that in each model node, power demand plus export equals power generation plus import. Balancing restrictions such as capacity installation limits due to area availability, power generation limits due to meteorological conditions, storage and demand response potentials are parametrized according to preceding energy data analyses (Scholz, 2012). Additional constraints such as political goals in the form of shares of power generation from renewable energy sources, levels of national energy or power self-sufficiency, or emission caps may also be included.

REMix-OptiMo is set up in a modular structure. Power generation technologies considered in this work comprise solar PV, CSP, wind, run-of-river hydro, reservoir hydro, geothermal, biomass, as well as conventional power plants using nuclear or fossil fuels. Additional balancing is provided by direct current (DC) power transmission and electricity-to-electricity storage. A detailed discussion of mathematical equations representing the essential characteristics of power generation, storage and transmission technology modules can be obtained from (Scholz et al., 2016). A brief, qualitative description is provided in the following section.

2.2 Technology Modelling in REMix

2.2.1 Wind, Photovoltaic and Hydro Run-of-river Power

VRE technologies without storage - wind, PV and hydro run-of-river - are treated in one module. REMix-EnDAT provides maximum installable capacities and normalized hourly power generation profiles for each technology. The technology potential sets the upper limit for capacity optimization. The calculation of VRE generation potentials and hourly time series with REMix-EnDAT is thoroughly described in (Scholz, 2012) and (Stetter, 2014). VRE curtailments can be enabled, and the model assures that the hourly power output equals sum of grid feed-in and curtailment.

2.2.2 Reservoir Hydro Power

In contrast to run-of-river stations, reservoir hydroelectric power plants have a storage option. The input to the water reservoir is subject to irregular and regular fluctuations depending on climate and weather. However, power generation can be adjusted within the restrictions given by reservoir size, filling level and minimum water flow rate. This enables both the provision of adjustable renewable electricity and pumped hydro storage. The technology module of reservoir hydro stations takes into account capacities of all major plant components: turbine, storage reservoir and pump. A capacity expansion of turbines and pumps can be considered, as well as revision outages and minimum turbine flow rates. Hourly time series provide the average natural inflow to the water reservoirs in each data node.

2.2.3 Concentrated Solar Power

CSP power plants can be equipped with thermal energy storage (TES) and backup firing systems allowing for round the clock power generation. In REMix-OptiMo, the installed capacities of all components can either be defined by the user or optimized by the model. Furthermore, an upper limit to the power generation share of the backup unit can be defined. Down regulation of the solar power output is optional. With all capacities set, REMix-OptiMo optimizes the hourly operation of CSP plants. The thermal output of the solar fields is provided as an input by REMix-EnDAT. The TES energy balance takes into consideration hourly changes in the storage level caused by charging, discharging and self-discharging. Thermal energy losses arising during storage charging and discharging can be defined.

2.2.4 Biomass and Geothermal Power

Resources for biomass and geothermal power generation are assumed to be constantly available throughout the year. This implies that the hourly power output is only restricted by the installed generation capacity and endogenously determined by the model. The annual power generation of all biomass and geothermal stations is however limited by the overall resource inventory.

2.2.5 Conventional Power Generation

Conventional power plants comprise nuclear, hard coal, brown coal and gas stations. As no limit in fuel availability is considered, their power production is only restricted by the available capacity. The model implementation allows for the consideration of internal power consumption, power change wear and tear costs, as well as carbon capture and storage (CCS) technology.

2.2.6 Direct Current Power Transmission

High voltage direct current (HVDC) technology can combine long distance power transport with comparatively low losses. In this module, DC power transmission technologies with different capacities and voltages can be implemented. Concerning costs and transmission losses, a differentiation between underground and sea cables on the one hand, and overhead lines on the other, can be made. HVDC interconnections and transmission capacities between model nodes can be user-defined or added in the optimization. Power losses are taken into account based on distances between the model nodes and scale linearly with power transmission.

2.2.7 Electricity-to-electricity Energy Storage

This module is designed to represent storage technologies with electric power input and output, such as pumped hydro storage, compressed air storage, hydrogen storage or batteries. Energy storage unit and converter unit are modelled separately. Hourly power input, output and storage level are limited by the corresponding installed capacities. Storage capacity optimization can be performed either with or without maximum installable capacities and a fixed storage-to-converter ratio. Resource limits and capital costs are assessed independently for storage and converter unit. Losses during charging, discharging and storing can be considered, and are integrated into the hourly storage level balance equation.

2.3 Scenario Definition

In order to study the correlation between VRE penetrations on the one hand, and balancing needs and costs on the other, we take into account a set of 66 scenarios. The scenarios differ in overall VRE share s_{VRE}, solar-to-wind r_{S2W} and CO_2 certificate price. We define the VRE share as theoretical share, as it would be reached, if no VRE power generation were curtailed or lost in storage and transmission. It is calculated as proportion of wind and solar power in overall generation according to equation (1), where index *i* accounts for all considered generation technologies.

$$s_{VRE} = \frac{W_{PV} + W_{CSP} + W_{Onshore} + W_{Offshore}}{\sum_i W_i} \qquad (1)$$

The solar-to-wind ratio r_{S2W} is calculated from the theoretical annual power generation of PV, CSP and wind according to equation (2). In this work, we vary the overall VRE share s_{VRE} from 0% to 100%, whereas for the solar-to-wind r_{S2W} values of 0.25, 1 and 4 – equivalent to mixes of 20-80, 50-50 and 80-20 – are taken into account (see Figure 2). The contributions of PV and CSP to overall solar power generation and of onshore and offshore to overall wind power generation are subject to optimization.

$$r_{S2W} = \frac{W_{PV} + W_{CSP}}{W_{Onshore} + W_{Offshore}} \qquad (2)$$

We assess each combination of VRE share and solar-to-wind ratio for three different CO_2 certificate prices. Like this, we study the dependency of the technology contributions in the provision of balancing power on the variable operational costs of fossil-fuelled power plants. Among other factors, VRE shares actually depend on the CO_2 certificate price. This makes certain scenarios more likely than others. However, the VRE shares that correspond to specific CO_2 certificate price values are unknown. Therefore, we investigate the whole parameter space in order to identify least-cost scenarios and the cost differences of alternatives. The designation of scenarios used in the following is composed of the VRE share, followed by solar-to-wind ratio and CO_2 price scenario, e.g. VRE20_Solar50Wind50_LCP in case of a 20% VRE share equally provided by solar and wind and under consideration of a low CO_2 price.

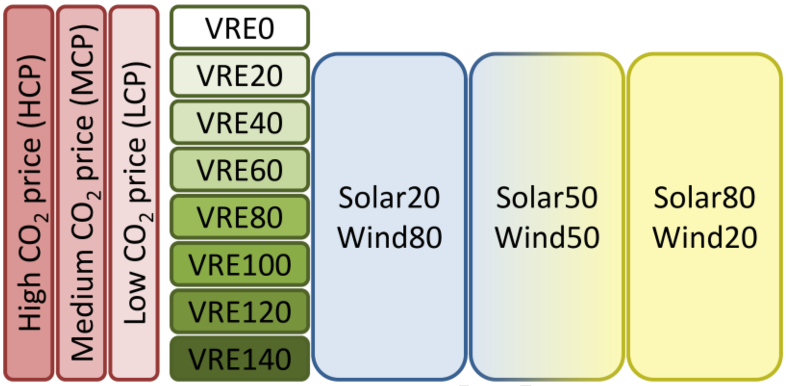


Figure 2: Overview of the analysed scenarios. The numbers indicate the corresponding shares in percent of overall supply. VRE shares range between 0% and 140%, solar and wind shares in VRE supply between 20% and 80% each.

For the evaluation of power transmission, as well as the regional allocation of power generation and storage, we subdivide the overall assessment area into 15 regions (see Figure 3). Power transmission within regions is not taken into account ("copper plate"). All power plants within each region are considered as one aggregated unit, no single stations or blocks are represented.

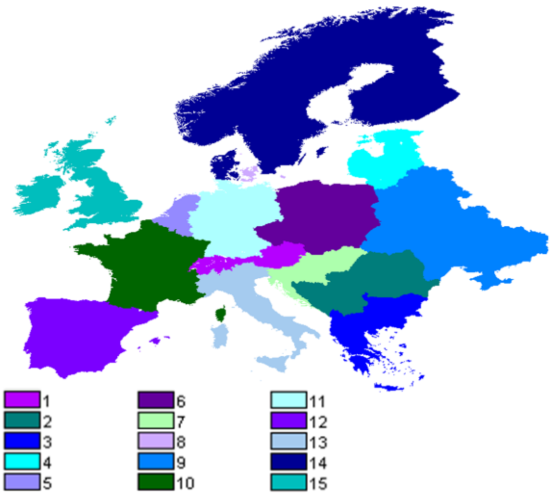


Figure 3: REMix model regions considered in the simulations.

Table 1: Countries included in each model region.

	Region	Countries included
1	Alps	Austria, Switzerland
2	BalkansNorth	Bosnia and Herzegovina, Romania, Serbia, Montenegro
3	BalkansSouth	Albania, Bulgaria, Greece, Macedonia
4	Baltic	Estonia, Latvia, Lithuania
5	BeNeLux	Belgium, Luxemburg, Netherlands
6	CentralEast	Czech Republic, Poland, Slovak Republic
7	CentralSouth	Croatia, Hungary, Slovenia
8	Denmark_W	Denmark West
9	East	Belarus, Moldova, Ukraine
10	France	France
11	Germany	Germany
12	Iberia	Portugal, Spain
13	Italy	Italy
14	Nordel	Denmark East, Finland, Norway, Sweden
15	UK_IE	Ireland, United Kingdom

Additionally to the power generation shares and CO_2 certificate price, the model input includes capacity limits for renewable energies, transmission grids and pumped hydro storage, as well as fuel costs and techno-economic technology parameters. These are introduced in section 2.5. The electricity supply optimization case study presented in this work considers 17 power generation technologies, seven electricity storage technologies and one DC transmission technology.

Taking into account the predefined VRE supply structure and technology parameters, the model evaluates the least cost capacity expansion and operation of each technology. The system dispatch is optimized for 8760 time slices representing the hours of one year. The system costs to be minimized are composed of the proportionate investment and fixed operational costs of all endogenously installed system components for one year of their amortization time, as well as the variable operational costs of all technologies. Depending on the technology, the latter may comprise variable production costs, fuel and CO_2 certificate costs.

2.4 Integration Costs

Integration costs are a concept used to quantify the challenge of integrating VRE into a power sector (Ueckerdt et al., 2013; Hirth et al., 2015). Although the calculated value depends on the reference case and the assumptions about technology availability, technology costs and resource prices, they can be a helpful metric to roughly compare integration challenges across different studies and models. Following the definition in

(Ueckerdt et al., 2013), integration costs of a technology include all costs arising due to the addition of this technology. We here classify the integration costs into four categories:

1) costs for the extension of long-distance transmission grids between EU countries, which allows to pool both variable generation and variable demand over larger areas

2) costs for additional investments into storage, which helps to balance generation and demand

3) an aggregated category that we call “utilization costs”. When a certain amount of conventional generation is reduced and replaced by VRE, one usually observes that the total cost for the residual system decreases less than proportionally to the reduced electricity generation[1]. This is equivalent to saying that the average cost per unit of residual electricity increases when the VRE share increases. The reason for this increase is that with increasing VRE share, in most power systems the ratio of (cheap) baseload electricity to expensive peak electricity decreases. Utilization costs then represent the costs arising as the residual power system shifts to more mid- and peak load due to VRE production, or equivalently, as the capacity factor of the residual system decreases

4) costs arising from curtailment of VRE power in times when VRE generation is higher than demand. While these costs might be subsumed under the generic VRE costs, we deem it helpful to single out how system-dependent curtailment increases the general LCOE that can be calculated from technology cost and resource quality.

While we here apply the concept only to VRE, it should be noted that it can be used for all technologies; baseload power like nuclear or lignite bring substantial utilization integration costs with them as they decrease the share of baseload to peaking electricity in the residual system.

For the first three categories, we follow the defining equation 6 in (Ueckerdt et al., 2013): For each category H, we first calculate the average cost by dividing total cost in this category (either grid, storage, or residual system) by the total amount of residual electricity E^R in a given scenario S. We then take the difference between this average cost and the average cost in the scenario with same price assumptions but no VRE, S_{VRE0}. This difference is upscaled to the total residual system size in scenario S by multiplying with the residual

[1] This generalization is not true if the deployed VRE is highly correlated with peak load and thus can actually increase the ratio of base load to peak load of the residual system. This mostly happens in regions with high midday demand peaks, where the first few percent of PV can reduce the residual peak capacity.

electricity generation. We then divide the value by the net VRE generation E^{VRE} to calculate specific integration costs per unit of VRE electricity c^{int}.

$$c_{H,S}^{\text{int}} = \frac{\left(\frac{C_{H,S}}{E_S^R} - \frac{C_{H,S_{VRE0}}}{E_{S_{VRE0}}^R} \right) \cdot E_S^R}{E_S^{VRE}}$$

For the curtailment integration costs, we take a more direct route: First, we calculate average LCOE without curtailment by dividing total VRE costs C_{VRE} by total VRE generation (the sum of used VRE generation E^{VRE} and curtailment E^{Curt}). These LCOE are multiplied by the curtailed electricity to yield the total value that is lost, and then divided by the VRE power generation to calculate the lost value per unit of used VRE electricity:

$$c_{Curt,S}^{\text{int}} = \frac{\frac{C_{VRE,S}}{E_S^{VRE} + E_S^{Curt}} \cdot E_S^{Curt}}{E_S^{VRE}}$$

Total integration costs are calculated by summing over all four categories.

2.5 REMix Model Input Parametrization

REMix model input parameters include technology characteristics, as well as regional values of power demand, renewable energy and storage potentials. They are briefly introduced in the following paragraphs.

2.5.1 Power Demand

The overall annual power demand in the assessment area amounts to roughly 3650 TWh. Hourly values range between 262 GW minimum load and 586 GW peak load. It relies on the Trans-CSP report (Trieb et al., 2006), which provides a power supply scenario with high renewable energy shares for the EUMENA region composed of Europe, Middle East and North Africa. The basic two assumptions about the demand development are an economic catching up of countries with low GDP until 2050 linked to an increasing power demand, and efficiency measures that reduce the power demand continuously. The resulting European power demand grows until 2040 and then starts to decrease. Accounting for recent trends and policies, the scenario has been updated for (Scholz et al., 2014). The annual demand is disaggregated to the single hours of the year using historic load profiles. These have been obtained by national transmission grid operators, or approximated based on the available data. An overview of the methodology and data sources is provided by (Scholz, 2012). In accordance with the RE power generation, load profiles of the year 2006 are used.

2.5.2 Power Generation Technologies

In the model configuration used in the scenario assessment, we consider ten renewable and seven conventional power generation technologies. Limits in regional capacity installation are only applied to renewable technologies.

The power generation of solar PV, wind and run-of-river hydro power plants is given by the availability of the intermittent resources. For each technology and geographical region, hourly generation profiles are incorporated. They have been calculated with REMix-EnDAT using meteorological data on the one hand, and technological characteristics on the other (see (Scholz, 2012)). The profiles applied in this work rely on data for the year 2006 and represent an average RE availability, compared to other recent meteorological years. VRE technologies are described by their power generation availabilities, specific investment costs, amortization times, as well as fixed operational costs.

In this work, we account for three CSP configurations. They reflect different solar multiples, and thus operation pattern. The solar multiple is defined as the ratio of thermal output from the solar field, and the thermal input of the steam turbine. The configuration *CSP-base* has a solar multiple of 3.5 and represents a technology for base load power provision. In order to decouple power production from solar irradiation, the CSP plant is equipped with a thermal storage dimensioned to supply 18 hours of full load turbine operation. The configurations *CSP-mid* and *CSP-peak* are designed with lower solar multiples of 2.5 and 1, and equipped with TES allowing for twelve and six hours of turbine operation, respectively. For the provision of firm capacity, all CSP plants use natural gas-fired backup systems allowing for full load power block operation.

Table 2: Power generation technology parameters, extracted or derived from (Agency and Energinet.dk, 2012; Nitsch et al., 2012)**.**

Technology	η_{net}	Avail.	c_{invest}	c_{OMFix}	c_{OMVar}	t_{amort}
	%	%	€[2]/kW	% of invest/a	€/MWh	a
Solar PV	n.a.	95.0%	720	1.0%	0	20
Wind onshore	n.a.	92.0%	900	4.0%	0	20
Wind offshore	n.a.	92.0%	1800	5.5%	0	20
CSP-peak			730 (PB)			
CSP-mid	37.0%	95.0%	192 (SF)	2.5%	0	25
CSP-base			19 (TES)			
Biomass	45.0%	90.0%	2000	4.0%	2	25
Geothermal	11.0%	95.0%	7600	4.5%	0	20
Run-of-river hydro	n.a.	95.0%	n.a.	n.a.	0	n.a.

[2] € always refers to €2009

Reservoir hydro	90.0%	98.0%	n.a.	n.a.	0	n.a.
GT (gas turbine)	46.5%	94.8%	400	4.0%	0	25
GT-CCS	39.5%	94.8%	900	4.0%	7	25
CCGT	62.1%	96.0%	700	4.0%	0	25
CCGT-CCS	53.1%	96.0%	1200	4.0%	7	25
Coal	50.9%	89.6%	1500	4.0%	0	25
Coal-CCS	43.9%	89.6%	2000	4.0%	12	25
Nuclear	30.9%	90.0%	5000	4.0%	0	25

Thermal power plants are mostly characterized by their electric efficiency η. Further model parameters include plant availability factors f_{avail}, as well as investment c_{invest} and operational c_{OM} costs. The calculation of investment annuities furthermore requires the definition of an amortization time t_{amort} and capital interest rate. For the latter, a value of 6% is applied to all investments. Possible efficiency reductions in part load operation are not taken into account for any power generation technology. Additional parameters arise from the consideration of TES in case of CSP and CCS in case of selected conventional power plant technologies. Independent of the CSP dimensioning, TES input to output efficiencies are assumed with 95%. To the corresponding technologies, a CCS factor of 0.9 is applied, equivalent to a 90% reduction in emissions. Reservoir hydro power stations are furthermore described by a pumping efficiency and minimum flow rate. The latter assures that the downstream water resource availability is not jeopardized. In this work, a norm minimum flow rate equivalent to 25% of the annual discharge average is applied. In regions where the natural water inflow to the reservoir goes below this threshold in single time-steps, the minimum flow rate is reduced to the respective values. It is taken into account that some reservoir hydro stations dispose of pumps allowing for the provision of negative balancing power; in this work we apply a pumping efficiency of 89%. Furthermore, we assume that reservoir hydro potentials in Europe are already completely exploited, thus no endogenous capacity expansion is possible. The annual geothermal and biomass resource availability, VRE capacity limits, as well as installed reservoir hydro power generation capacities in each region are summarized in Table 5 in the supplementary material. Table 2 contains the techno-economic power generation parameters of all technologies, assumed to represent close to mature technologies in the middle of the 21st century.

2.5.3 Power Storage Technologies

In this assessment, three different storage technologies are taken into account: redox flow battery (RFB), pumped hydro and hydrogen storage. RFB and hydrogen tanks are chosen as representatives for short and long term storage technologies, respectively, which are not subject to any direct limitation in resource availability. In order to consider different storage designs, three configurations each of RFB and hydrogen storage are included. RFB can be installed with the ratio of storage to converter unit of four, seven and 24 hours, hydrogen storage with 100, 400 and 800 hours. For pumped hydro, we assume that the storage capacity of the year 2010 will be available also in the future. It must however be complemented by a model endogenous installation/refurbishment of converters, which are in their capacity limited to the values of the year 2010.

All storage technologies are characterized by their charging and discharging efficiencies, self-discharge rate, availability and costs. The latter are composed of investment costs, amortization times and fixed operational costs. Table 3 summarizes the techno-economic storage parameter applied in this work.

Table 3: Electricity storage technology parameters.

Technology						Storage		Converter		
	f_{S2C}	η_{charge}	$\eta_{discharge}$	$\eta_{selfdischarge}$	f_{avail}	c_{invest}	t_{amort}	c_{invest}	t_{amort}	c_{OMFix}
	hours	%	%	%/h	%	€/kWh	years	€/kW	years	% of
RFB_4	4	90%	90%	0%	98%	100	20	300	20	3%
RFB_7	7	90%	90%	0%	98%	100	20	300	20	3%
RFB_24	24	90%	90%	0%	98%	100	20	300	20	3%
Pumped Hydro	-	89%	90%	0.001%	98%	0	60	640	20	3%
Hydrogen_100	100	70%	57%	0%	95%	1	30	900	15	3%
Hydrogen_400	400	70%	57%	0%	95%	1	30	900	15	3%
Hydrogen_800	800	70%	57%	0%	95%	1	30	900	15	3%

2.5.4 DC Power Transmission

In order to provide inter-regional balancing of VRE generation and demand, DC power lines can be endogenously installed by the model. The grid capacity expansion is limited to point-to-point DC connections between neighbouring model regions. HVDC lines with a nominal power of 1.5 GW can be added up to an overall capacity of 30 GW per connection. According to (Trieb et al., 2012), we assume DC transmission power losses of 0.45%/100 km on land and 0.27%/100 km in sea cables. Additional 0.7% is lost at conversion from and to AC. Investment costs differ substantially for overland lines on the one hand and sea cables on the other: here values of 490 k€/km and 1953 k€/km are applied, respectively. Additional costs of 162 000 k€ each arise from the installation of converter stations. All components have an amortization time of 40 years and annual fixed operational costs equivalent to 0.6% of the investment (Trieb et al., 2012).

2.5.5 Fuel Costs and CO_2 Certificate Prices

In order to reflect different future developments in CO_2 trading systems, we consider three CO_2 emission certificate prices: 50 €/t in the low certificate price (LCP) scenario, 150 €/t in the medium certificate price scenario (MCP), and 400 €/t in the high certificate price scenario (HCP).

For the fuel costs, we assume identical values across all scenarios: 9 €/MWh for coal, 28.8 €/MWh for natural gas, 7.2 €/MWh for uranium and 36 €/MWh for biomass, all referring to the calorific value of the fuel before conversion.

3 Results

The REMix results provide least cost capacity installation and operation of all system components. The presentation is subdivided into three parts: evaluation of the resulting power plant, storage and grid capacities (section 3.1), analysis of the system operation (section 3.2), and derivation of VRE integration costs (section 3.3).

3.1 Capacity Expansion

3.1.1 VRE Supply Structure

Overall solar and wind supply power generation in each scenario are predefined by VRE share s_{VRE} and solar-to-wind ratio r_{S2W}. In contrast, the proportions of PV and CSP in the solar share and of wind onshore and wind offshore in the wind share are determined endogenously by REMix, taking into account the restrictions posed by the available potentials. Figure 4 shows the resulting proportions and total VRE capacities for the medium CO_2 certificate price scenarios, depending on the theoretical solar and wind shares, i.e. the ratio of annual solar and wind power generation before curtailments to the annual power generation. The VRE capacities are related to peak load, i.e. the highest hourly European load, which amounts to 586 GW and is around 5% lower than the sum of the regional peak loads.

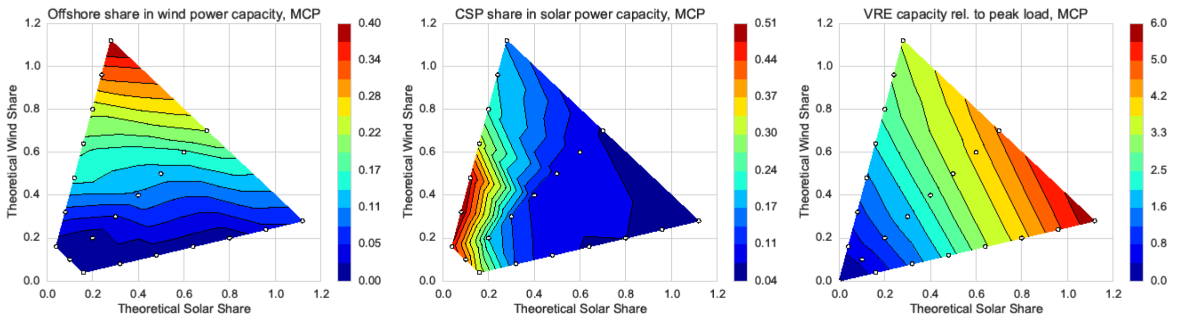


Figure 4: Offshore share in overall wind power capacity (left), CSP share in overall solar capacity (centre) and overall VRE capacity relative to peak load in the scenarios with medium CO_2 certificate price.

The subdivision to the two available wind power technologies is mostly dependent on the overall wind share (see Figure 4, left). When wind theoretically covers less than 20% of the annual power generation, only onshore wind is used. For higher wind shares, the offshore share gradually increases to around 40% in the scenario with highest wind power utilization. It is found to rise approximately proportionate to the overall wind share. The applied CO_2 certificate prices have little impact on the proportions of onshore and offshore wind: the offshore share slightly decreases for higher certificate costs, from an average of 16.6% in LCP to 15.8% in MCP and 15.5% in HCP scenarios.

CSP generation capacity is installed in all scenarios with VRE contribution. The absolute capacity increases with VRE and with wind share and reaches a maximum of 151 GW at a solar dominated VRE share of 120%. However, its share in total solar generation capacity reaches highest values of up to 50% in the scenarios with low solar share (see Figure 4, centre). It is particularly high in supply systems dominated by wind power. It decreases below 25% for solar shares of approximately 20%, and below 10% for solar shares exceeding 50%. The CSP share decreases with the solar share because of the limited European potentials. The high gradient of reduction is due to the much lower annual full load hours (FLH) of PV which leads to higher installed capacities for the same energy yield. While the share of CSP in total solar capacity falls to around 5% at the highest VRE shares, the share of CSP in total solar power generation is only reduced to around 20%. The CO_2 certificate prices are found to have only a minor impact on the solar technology proportions.

The right diagram in Figure 4 shows the overall VRE generation capacity installation in all scenarios with medium CO_2 certificate prices. Due to the lower average capacity factors of PV, much higher values are found in the scenarios with high solar shares. This effect mainly occurs above 40% of overall VRE penetration and increases substantially for higher VRE shares, reflecting the decreasing share of CSP identified at higher solar power penetration. At higher VRE shares, the overall capacity in solar-dominated systems exceeds that in wind-dominated systems by up to two thirds. It reaches a maximum of 3474 GW in scenario VRE140_Solar80_Wind20_HCP, compared to 2002 GW in VRE140_Solar20_Wind80_HCP. These capacities are equivalent to roughly 6 times and 3.5 times the annual peak load, respectively. Since theoretical VRE shares are pre-set in the scenario definition, the CO_2 certificate prices hardly influence the total capacity of the VRE power plant park: on average, it is by 1% higher in the MCP scenarios, and by 2% higher in the HCP scenarios, both relative to the LCP scenarios.

3.1.2 Power Storage

The power storage capacity installation exhibits significant differences between the scenarios. Due to the characteristic power generation pattern of solar on the one hand and wind on the other, different storage technologies are employed. Battery and pumped hydro storage reach highest capacities in the scenarios dominated by solar power, whereas hydrogen storage is only built in scenarios with high wind power share and high CO_2 certificate price. The storage installation is highly dependent on the applied emission costs and thus the variable costs of conventional power plants. At higher CO_2 certificate prices, storage is increasingly used for achieving higher net VRE supply shares, avoiding the installation and operation of conventional power plants. The storage converter capacity installation in MCP and HCP scenarios exceeds the installation in LCP scenarios by 42% and 73% respectively. This is equivalent to an average additional capacity of 22 GW and 39 GW, respectively. The increase in storage converter capacity is particularly high in the scenarios dominated by solar power.

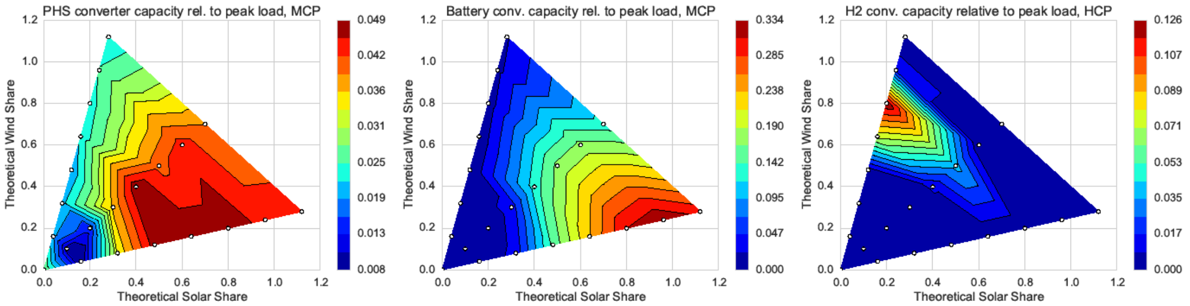


Figure 5: PSH (left) and battery (centre) converter capacity installation in the scenarios with medium CO_2 certificate price. Hydrogen storage (right) converter capacity installation in the scenarios with high CO_2 certificate price. All values relative to peak load.

Figure 5 shows the PSH converter capacity installation relative to the annual peak load in the scenarios with medium CO_2 certificate costs. Highest values of around 5% are found at VRE shares between 60% and 100% with half of it provided by solar power. On the contrary, lowest PSH installation takes place in the scenarios with 20% VRE share, especially when dominated by solar power. In these cases, the high demand during the day is reduced by solar power generation and thus storage becomes less beneficial to the system.

Battery storage complements and partially substitutes pumped hydro storage at high solar shares (see Figure 5). Its converter capacity reaches up to 33% of peak load in scenario VRE120_Solar80Wind20_MCP. In contrast, almost no batteries are used in the scenarios dominated by wind power, as well as VRE shares below 40%. The battery storage converter capacity installation is particularly sensitive to the assumed emission costs. In the scenarios with medium and high emissions costs, the overall capacity is on average by 46% and 66% higher than in the case of low emission cost, respectively. The minimum battery capacity installation does not occur in the system without VRE, but for low wind shares (<10%) and solar shares between 10% and 20%.

Hydrogen storage is only used in the scenarios with high CO_2 certificate price. The resulting converter capacity relative to the annual peak load in each scenario is provided in Figure 5. It is highest in the scenario with 80% wind and 20% solar power, where it reaches around 12% of the annual peak demand.

3.1.3 Transmission Grid

The installation of DC connections between model regions is first and foremost driven by the overall VRE share. At VRE shares exceeding 60% it furthermore highly depends on the contribution of wind energy. The overall grid capacity relative to peak load is shown for the scenarios with medium CO_2 certificate price in Figure 6.

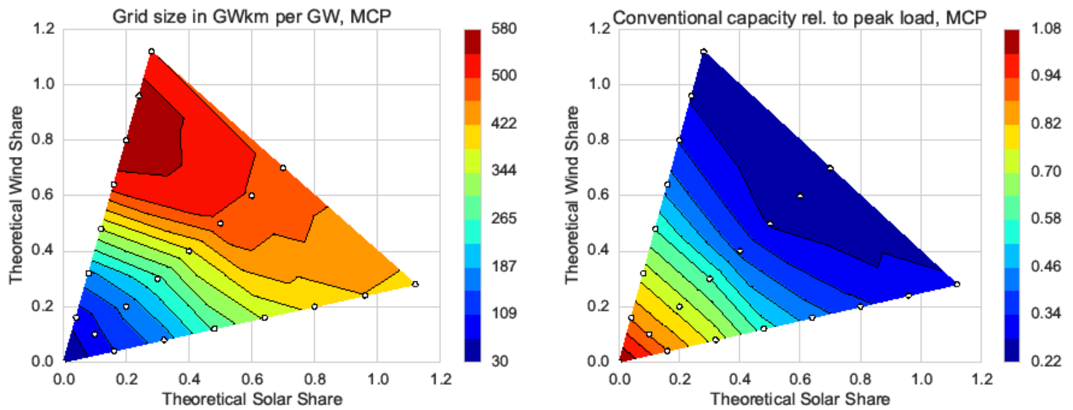


Figure 6: DC transmission capacity installation in GWkm/GW (left) and conventional power plant capacity installation (right) in the scenarios with medium CO_2 certificate price. All values relative to peak load.

Grid capacities are highest for wind shares of around 80% to 100% and solar shares between 20% and 30%, reaching up to around 580 GWkm per GW of peak load in the MCP scenarios. With further increasing wind shares, transmission capacity decreases again, while the grid utilization (see Figure 10) increases. On average over all scenarios and relative to LCP scenarios, the installation of transmission lines is by 14% higher in MCP and 16% in HCP scenarios. Thus, increasing CO_2 prices mainly trigger transmission capacity installation between low and medium emission certificate prices.

3.1.4 Conventional Power Plant Capacity

With increasing VRE share, conventional power plants are gradually replaced by VRE, grid and storage. Nonetheless, substantial installed capacities remain. The right diagram in Figure 6 exemplarily shows the overall conventional power plant capacity in the scenarios with medium CO_2 certificate price. It amounts to 106% of peak load (621 GW) in the scenario without any VRE and reaches its lowest value of 22% of peak load (131 GW) in the scenario with 60% wind and 60% solar share. The diagram exhibits a very symmetric pattern, which implies that the decrease in conventional power plant capacity is mainly given by the overall VRE share, and not by the proportions of solar and wind. It tends to be slightly lower for equal shares of both resources.

The conventional power plant technology choice depends on the combination of investment, operation, fuel and emission certificate costs and capacity utilization. Higher capacity utilization promotes coal, lower capacity utilization promotes gas. Fuel and emission certificate costs for coal and gas are opposing each other: coal has lower fuel costs but higher emissions per energy unit than gas. There is typically one technology used for base load provision, which dominates the power plant park for VRE shares of less than 80%: following from the specific emissions, the preferred base load technology changes from CCGT to Coal-CCS to CCGT-CCS with increasing CO_2 certificate price. Additionally, one or various technologies with lower investment costs are used for peak supply. With increasing VRE share, the installed capacity of the base load technology is gradually reduced and partially substituted by the peak load technologies. CCS technologies are not used in the scenarios with low, but in those with medium and high CO_2 certificate price. Table 4 provides an overview of the technology choice made by REMix, Figure 7, Figure 8 and Figure 9 show the resulting power plant park for each scenario for low, medium and high certificate costs, respectively. Not only the composition, but also the overall size of the power plant park is influenced by the CO_2 price. For most VRE shares and proportions, it is highest in the case of medium CO_2 price.

Table 4: Conventional power plant technology choice.

CO_2 certificate price	Base load technology	Peak load technology
LCP (50€/t)	CCGT	GT
MCP (150€/t)	Coal-CCS	CCGT, CCGT-CCS and GT
HCP (400€/t)	CCGT-CCS	GT and GT-CCS

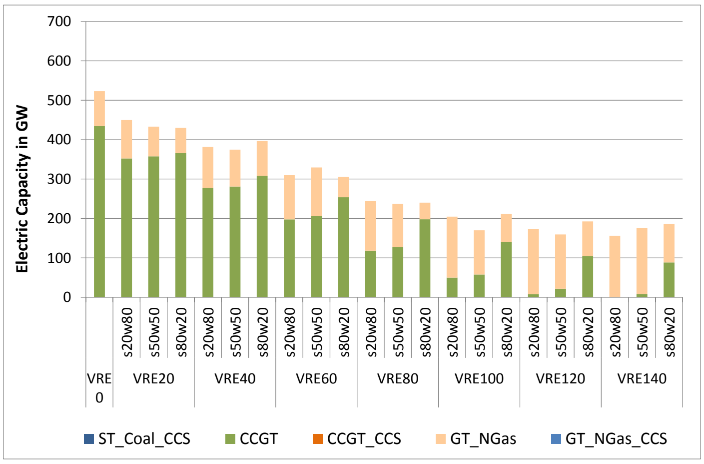


Figure 7: Conventional power plant technology installation in the scenarios with low CO_2 certificate price.

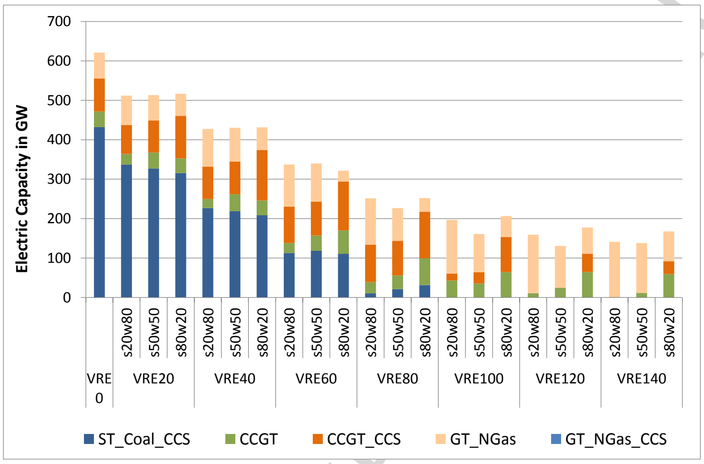


Figure 8: Conventional power plant technology installation in the scenarios with medium CO_2 certificate price.

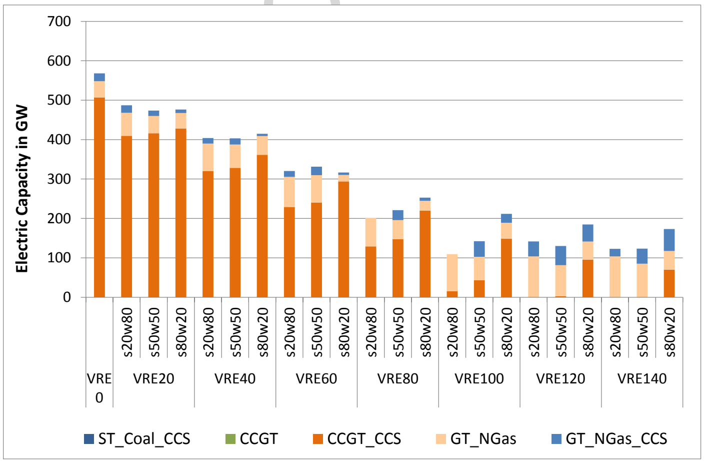


Figure 9: Conventional power plant technology installation in the scenarios with high CO_2 certificate price.

3.1.5 Other Renewable Energy Power Plant Capacity

In addition to VRE and conventional power plants, electricity is furthermore generated in reservoir hydro and run-of-river hydro stations. Their capacity is given as scenario input (see paragraph 2.5.2 and Table 5). Their power generation depends on the characteristics of the remaining system and varies due to small curtailments between 13.4% and 15.2% of the annual power demand in all scenarios. Biomass and geothermal power are available as investment options, but not deployed in any of the scenarios. This implies that their costs are too high compared to the alternative technologies.

3.2 System Operation

3.2.1 VRE Generation and Curtailments

Due to the high simultaneity of fluctuations in VRE power generation, the limited capacity and the losses of grid and storage, not all VRE electricity production can be used. Differences between theoretical and actual VRE share result from curtailments on the one hand, and losses in transmission and storage on the other.

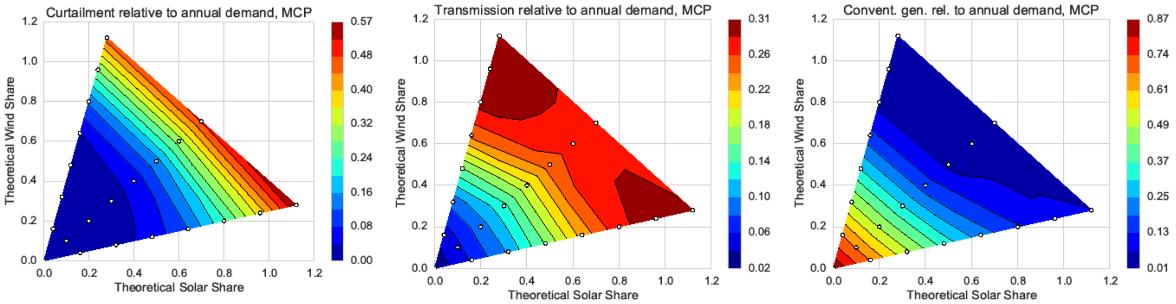


Figure 10: Annual VRE curtailment (left), transmission (centre) and conventional power generation (right) relative to annual demand in the scenarios with medium CO_2 certificate price.

For the first 40-50% of VRE share, assuming a perfect internal transmission grid within each country, curtailment stays below 1% of annual power demand. When VRE shares increase beyond 50-60%, the cost-optimal amount of curtailment increases, but still stays below 25% until theoretical VRE shares of 100%. Only at very high theoretical shares of 120 and 140%, curtailment increases up to levels of 60%. One must notice here that the power generation in the preset hydro power plants amounts to around 15% of annual power demand, which limits the real VRE contribution to demand coverage to around 85% at most.

In solar-dominated systems, curtailments generally arise at lower shares and reach higher overall levels than in wind-dominated systems (see Figure 10, left). Maximum net solar generation, i.e. after curtailments, amounts to 59% and maximum net wind power generation to 66% related to annual power demand.

Higher CO_2 emission certificate prices go along with higher installation of grid and storage capacities and thus lead to reduced curtailment. On average over all scenarios, curtailment is by 3% lower in MCP and by 26% lower in HCP scenarios, both compared to LCP scenarios.

3.2.2 Power Storage Output and Losses

The annual energy output from storage units is approximately proportional to the installed capacity. It is shown for the medium CO_2 certificate price in Figure 11 (on the left). Highest values of around 12% of the annual demand are found in the scenarios with 100% to 120% theoretical VRE share, of which 80% are provided by solar and 20% by wind power. On average over all scenarios, the annual storage output reaches 2.3% of the demand in the LCP case, 3.3% in MCP and 3.6% in HCP cases.

The centre diagram in Figure 11 shows the resulting storage losses in the scenarios with medium CO_2 price. They reflect that storage is preferably built in the scenarios dominated by solar power. Storage losses increase at higher solar shares, and reach around 3% at maximum.

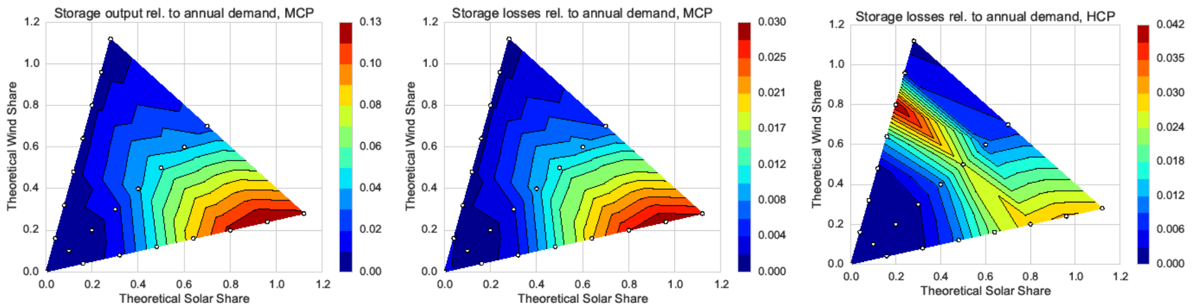


Figure 11: Total storage output (left) and losses (centre) at medium CO_2 certificate price, and total storage losses at high CO_2 certificate price (right). All values relative to annual power demand.

Due to the installation of hydrogen storage, a different pattern arises in some of the high CO_2 emission certificate price scenarios (see Figure 11, on the right). Highest losses are found in the scenario with 80% wind and 20% solar power, which is characterized by the highest hydrogen storage installation. At even higher wind shares, the capacity and the losses of hydrogen storage decrease again and thus the overall storage losses.

3.2.3 Transmission Grid Utilization and Losses

The central diagram in Figure 10 shows the transmission after transmission losses, i.e. the sum over all power imports, relative to the annual demand in the scenarios with medium certificate costs. It reaches up to 25% in the scenarios with more than 100% VRE. At high VRE shares, values are particularly high in supply systems unilaterally dominated by wind or solar power, whereas they are lower at VRE mixes with equal wind and solar shares. Comparing the installed grid capacity and the overall energy transmission it appears that the average utilization of transmission lines is higher in the scenarios with more solar capacity. On average over all VRE shares and CO_2 emission certificate prices, it reaches around 3.1 TWh/a/TWkm in scenarios with 20% solar and 80% wind share, 3.2 TWh/a/TWkm in scenarios with equal contributions, and 3.9 TWh/a/TWkm in scenarios with 80% solar and 20% wind share.

Like curtailment, electricity losses due to storage and transmission increase with VRE shares. The overall losses, however, range at much lower levels than the VRE curtailments. The scenario-specific grid losses reflect the annual utilization and reach highest values of around 2% of the annual demand at VRE shares between 100% and 120%, particularly in the systems unilaterally dominated by wind or solar power.

3.2.4 Conventional Power Generation

The conventional power generation amounts to around 85% of the power demand in all scenarios without VRE contribution. The remaining 15% are provided by hydro power. With growing VRE shares, the conventional power generation is reduced but does not reach zero in any of the analysed scenarios. It amounts to around 1% of the annual demand in the scenarios with a VRE share of 140%, a solar share of 20% and a wind share of 80%, hardly varying with the CO_2 emission certificate price. Below an overall VRE share of 80%, the decrease is almost symmetric, i.e. independent from the solar and wind proportions. Above this share, the conventional power generation in wind dominated systems decreases stronger than in solar dominated systems (see Figure 10).

The average capacity utilization decreases strongly from 5000 FLH/a in the medium CO_2 certificate price scenario without VRE contribution to 266 FLH/a in scenario VRE140_Solar20Wind80_MCP. At high VRE shares FLH are generally higher for solar dominated systems than for wind dominated systems. Annual FLH depend on the CO_2 emission certificate price as well: on average, they are around 15% higher in the LCP scenarios and around 5% lower in the HCP cases than at medium CO_2 certificate price. In the extreme cases, deviations of +30% and -15% occur.

3.2.5 Supply Costs

We calculate levelised costs of electricity (LCOE) of the whole supply system by dividing the total annual supply costs, i.e. the sum of annuities and variable costs of all system components, by the annual power demand. The results are shown in Figure 12. The LCOE ranges are 0.082 – 0.117 €/kWh in the LCP scenarios, 0.092 – 0.119 €/kWh in the MCP scenarios and 0.104 – 0.121 €/kWh in the HCP scenarios.

At zero VRE penetration, all scenarios for a given CO_2 certificate price of course have the same costs, at higher VRE penetrations levels, the VRE proportions become the determining factor for the LCOE. The overall minimum LCOE always occur in the scenarios wit 20% solar and 80% wind contribution, but at different overall VRE penetration rates for the different CO_2 emissions cost levels: at low certificate price, a theoretical 40% VRE penetration level is cost minimal, at medium certificate price, the cost minimum is shifted towards 60% VRE penetration and at high certificate price, it occurs at 80% of VRE penetration. The LCOE in the scenarios with 50% solar and 50% wind contribution almost equal those at 20% solar and 80% wind contribution. On average, the differences are below 1%. In the scenarios that are dominated by solar power generation, the costs are clearly higher: in the LCP scenarios they exceed the Solar20Wind80-costs by 7% on average, in the MCP scenarios by 8.4% and in the HCP scenarios by 8.7% on average.

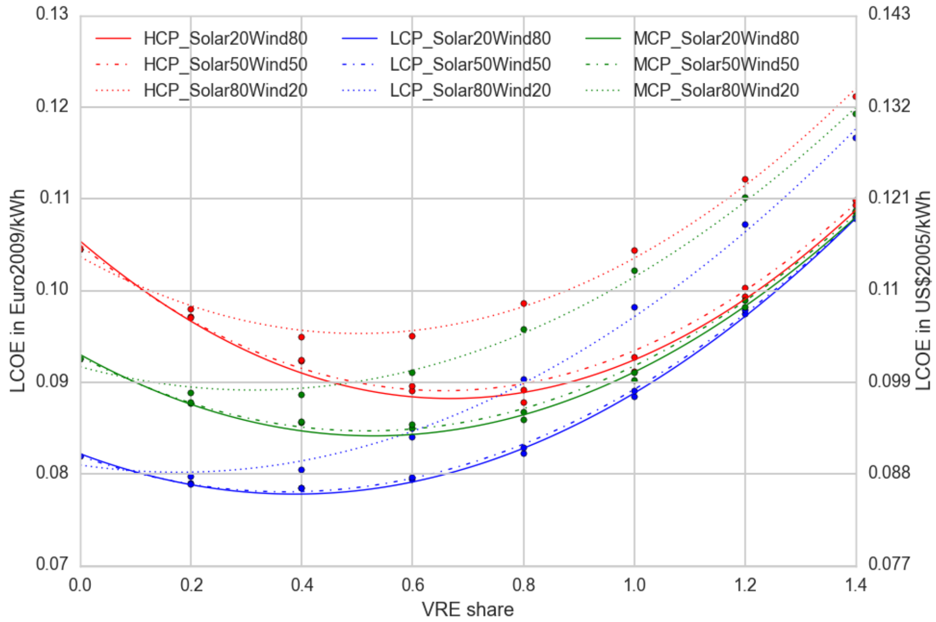


Figure 12: Levelised costs of electricity related to annual power demand in €/kWh (left y-axis) and in US$$_{2005}$/kWh (right y-axis) in the LCP, MCP and HCP scenarios.

The shares of storage and transmission in the LCOE have the same order of magnitude: for storage, the share is 2.1% and for transmission 2.5% on average over all CO_2 emissions certificate prices and VRE shares and proportions. According to the capacity installations, solar dominance particularly increases storage and wind dominance increases transmission costs (for comparison see Figure 5 and Figure 6). Transmission and its costs depends less on emission costs: the share in LCOE increases from 2.2% at low emission costs to 2.4% at medium and high emission costs, whereas the storage share in LCOE increases from 1.3% at low to 2.1% at high emission costs. The maximum cost shares reach 6.2% for storage and 4.4% for transmission, both in the high emission cost scenarios.

3.2.6 CO_2 Emissions

As expected, emissions decrease with increasing CO_2 certificate price. The highest emissions, which occur in the low certificate price scenario without VRE contribution, amount to 1010 Mt/a, i.e. to 0.27 t/MWh related to the annual power demand. They decrease almost proportionally with total VRE shares until around 60% VRE penetration; above this, they decrease faster with increasing wind than with increasing solar power generation. The overall minimum occurs in scenario VRE140_solar20wind80 and amounts to 7.1 Mt/a, i.e. 0.002 t/MWh of annual power demand.

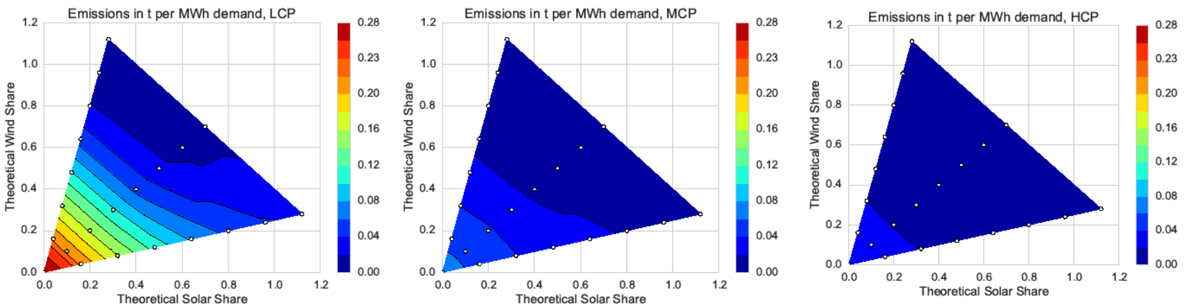


Figure 13: Emissions relative to power demand in t/MWh with low (left), medium (centre) and high (right) CO_2 certificate price.

3.3 Integration costs

We limit our discussion of integration costs to the scenarios with theoretical VRE shares up to 100%. Beyond that, curtailment costs increase to levels where they mask all other costs, as would be the case for any technology forced to generate more electricity than 100% of demand.

Total average integration costs for the modeled EU power system vary between 11 and 40 €/MWh$_{VRE}$ in the medium CO_2 emission certificate price scenarios, as displayed in Figure 14. The principle pattern of integration cost development with VRE share and solar and wind proportions is the same for all emission certificate cost scenarios, it only differs slightly in the absolute amounts: total integration costs are about the same in the low CO_2 certificate price scenarios and slightly lower (between 9 and 37 €/MWhVRE) in the high CO_2 certificate price scenarios. Therefore, only the medium certificate cost scenarios are described here.

3.3.1 Individual integration cost components

As shown in Figure 15, the four cost components exhibit individual patterns with respect to VRE share and ratio between wind and solar. Utilization costs are highest around 20-40%

VRE share and then decrease again; grid costs grow slightly with increasing VRE share. Storage and curtailment costs both increase strongly with increasing VRE shares and with increasing solar shares.

Utilization costs vary between 8 and 13 €/MWh$_{VRE}$. They depend more strongly on the ratio between wind and solar contribution than on the total VRE share: in solar dominated scenarios (80% solar and 20% wind), they are on average 22% higher than in wind dominated scenarios (20% solar and 80% wind). Up to 40% VRE, utilization integrations costs dominate the total integration costs, with a share of 60% to 81%. This share decreases to less than 39% at a VRE penetration of 100% and more.

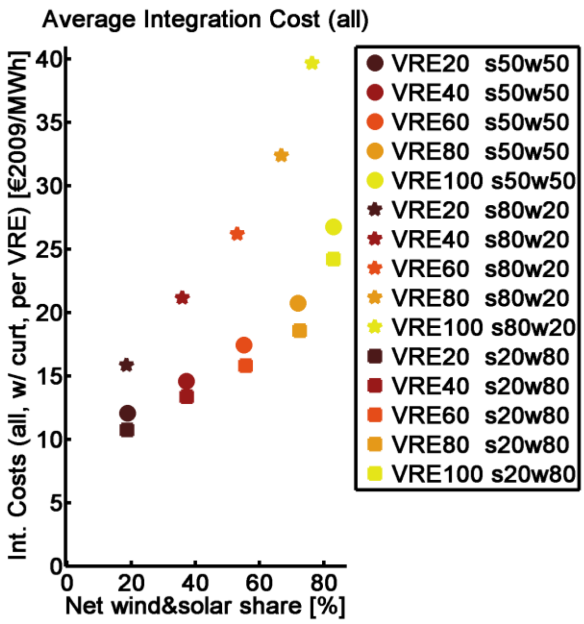


Figure 14: Average total integration costs across the MCP scenarios. The first term in the legend reports the theoretical VRE share before curtailment in a scenario, the second term describes the ratio of solar to wind in the theoretical contribution, and the values on the x-axis show the net VRE share after curtailment.

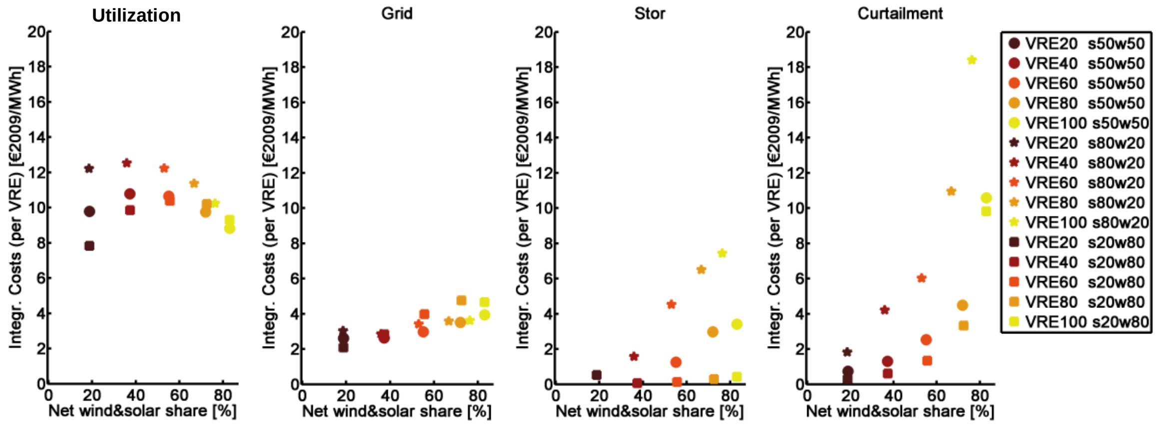


Figure 15: Average integration costs across the MCP scenarios for the four categories utilization, grid, storage and curtailment. The first term in the legend reports the theoretical VRE share before curtailment in a scenario, the second term describes the ratio of solar to wind in the theoretical contribution, and the values on the x-axis show the net VRE share after curtailment.

Storage costs vary between -1 and 7 €/MWh$_{VRE}$. They are negative at 20% VRE share if solar makes up at least half of the VRE generation. In these scenarios, the demand for storage in a power system without VRE (charging at night and discharging at daytimes to balance higher load during the day) is counteracted by the midday power generation from solar energy, making storage less economic. Only when solar reaches a higher share, storage again becomes economic, now used in the opposite direction: it is charged at daytime and discharged at night. On average, storage integration costs 4 €/MWh$_{VRE}$ more in solar dominated than in wind dominated systems. The maximum of 7 €/MWh$_{VRE}$ occurs in the scenario VRE100_s80w20. Storage integration costs have a share in total integration costs of between 9% and 20% in scenarios where solar makes up at least half the VRE generation, while in wind dominated systems the share is below 5% in all scenarios.

Grid costs depend least on VRE shares, they lie between 2.1 and 4.8 €/MWh$_{VRE}$ for all scenarios. They are generally slightly higher for wind dominated than for solar dominated systems. The grid integration cost share in total integration costs varies between 6% and 26%.

Curtailment costs are the integration cost category that depends most strongly on the VRE share: at low VRE shares they are as small as 0.3 €/ MWh$_{VRE}$, but rise to 18 €/ MWh$_{VRE}$ at 100% VRE share. Solar-dominated scenarios experience much higher curtailment; they have about twice as high curtailment costs compared to scenarios with similar VRE share but lower solar contribution. The maximum occurs in the solar dominated system with the highest VRE share; it then accounts for 46 % of total integration costs.

3.3.2 Variation of grid expansion assumptions

To explore the impact of the transmission grid expansion on VRE integration challenges, we additionally ran two types of scenarios with changed assumptions about grid expansion: In the "NoGrid" scenarios, we assumed that the transmission grid between the different regions is fixed and cannot be expanded, while in the "Cable" scenarios, the investment cost for HVDC lines is doubled. The Cable scenarios thus explore a world where large stretches of HVDC lines are realized as underground cables to reduce local opposition against new transmission lines.

The resulting integration costs for the scenarios with different VRE shares, an even wind-solar mix and a carbon price of 150€/tCO_2 are displayed in Figure 16. The results show the high integration value of grid expansion: foregoing the option to better connect areas with different time patterns of VRE and demand leads to a substantial increase of average integration costs by up to 90% at high VRE shares. In contrast, a doubling of grid costs only results in a small increase of integration costs. Accordingly, partially deploying more expensive underground cables seems a viable option to reduce local protests in densely populated areas without substantially increasing integration costs.

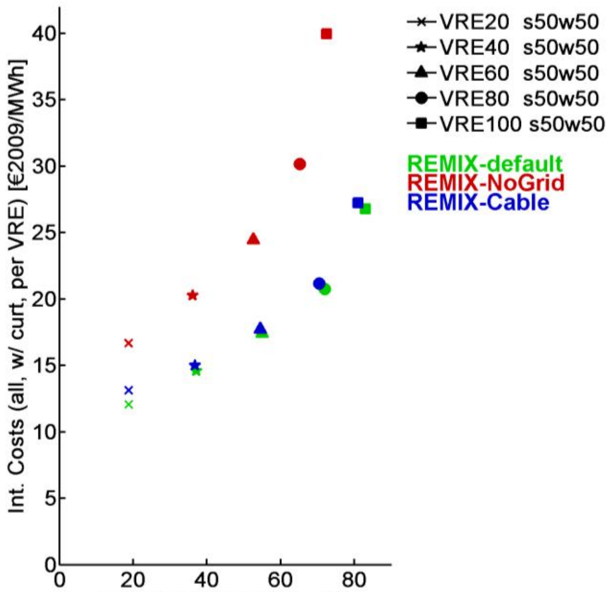


Figure 16: Average integration costs across the different grid scenario variations, for a carbon price of 150€/tCO_2 and a balanced wind-solar mix.

4 Discussion

In the evaluation of the results, it needs to be taken into account that by considering the existing hydro power infrastructure in Europe, the real VRE contribution to demand coverage can at most amount to around 85%. The remaining 15% are provided by hydro power which is assumed to operate at zero variable generation costs. Furthermore, when comparing the results to other studies, differing assumptions about the supply structure must be regarded: instead of pre-setting national installed capacities in order to assure a certain level of national autarchy, we assume a fully liberalised European market, i.e. the model endogenously installs capacities without national or regional defaults or restrictions other than the available potentials. Furthermore, it must be noted that the REMix results represent supply systems perfectly adapted to the predefined solar and wind shares. Deviations from the technology mix of grid, storage or backup power plants determined by REMix can change the need for alternative balancing technologies, as well as system operation and curtailment.

Our analysis reveals that the CSP potential with good resource quality is extensively exploited: overall, between 24 GW and 152 GW of electric capacity is installed with little impact of different CO_2 emission cost assumptions. A decrease of the CSP share in the solar share with growing VRE shares is due to potential limits. Thus, higher CSP shares might occur at higher solar shares if additional potential was available – e.g. assuming less restrictive land availability or imports from North Africa.

In a previous REMix application analysing the same VRE supply shares and solar-to-wind ratios as in this work, CSP was regarded a dispatchable and not a variable source of renewable energy (Scholz et al., 2016). This implies that there CSP competed with other dispatchable technologies and not with PV. The model results presented in (Scholz et al., 2016) reveal a maximum electric CSP capacity of 92 GW, which is considerably lower than the highest values found in this study. It is reached in a scenario without photovoltaic or wind contribution at medium CO_2 emission costs, and decreases with growing supply share of VRE and particularly of PV. As a consequence of the competition with CSP, conventional power plant capacities are found lower than in this work at low VRE shares, but higher at high VRE shares. Furthermore, the limitation of the solar VRE technologies to PV and thus reduction of CSP thermal storage availability leads to substantially higher capacities of short-term electricity storage. Much lower differences between this work and (Scholz et al., 2016) are identified for overall curtailments, aggregated dispatchable generation capacities, conventional power generation, as well as maximum net solar and wind supply shares. Furthermore, the maximum grid capacities are only to a minor extent affected by the consideration of CSP as dispatchable or variable power source, respectively. However, due to the concentration of CSP potentials to southern Europe, comparatively higher grid capacities are found at low VRE shares if CSP replaces dispatchable capacities that are evenly spread across Europe. Even though differences in power supply, transmission and storage capacities are substantial in some scenarios, the resulting LCOE are almost independent from the classification of CSP as dispatchable or variable solar resource: they differ by less than 1%.

The curtailments we find at 100% VRE and equal shares of solar and wind amount to 14% of annual power demand. As far as can be judged from the results visualisation in the studies cited in the introduction, this is about half of the curtailments in (Schaber, Steinke, Mühlich, et al., 2012) and somewhat more than half of those in (Rodriguez et al., 2015). There are several differences in the setup of these studies, but two obvious reasons for the lower curtailment we find are the storage expansion option in our study and that the main driver of curtailments, the PV share, is reduced through CSP.

Assuming an average VRE capacity installation density of 10 MW per square kilometre, the highest capacities 6 times the annual peak load would lead to an area requirement of around 4% of the European surface. This is the case for a theoretical VRE share of 140%. Such a high capacity installation may become economic and thus realistic if the transport and heat sector become increasingly electrified in order to reduce CO_2-emissions from these sectors, too.

The analysis of power transmission is limited to the evaluation of power flows between the considered model regions (see Figure 3). Network demand, operation and congestion within these regions cannot be assessed. Transmission capacity between regions is installed in all scenarios, even at zero VRE penetration. Grid capacities are especially high at high wind shares due to higher spatial balancing effects for wind than for solar power generation. In principle, this finding is in accordance with (Schaber, Steinke, Mühlich, et al., 2012) and (Scholz et al., 2016). However, we find maximum grid extension at wind dominated maximum net VRE penetration levels of 85% across all CO_2 certificate price scenarios, while (Schaber, Steinke, Mühlich, et al., 2012) see maximum grid extension at a wind dominated VRE penetration of only 30% to 50% when all European countries have their own national backup capacity and of 40% to 80% when backup capacities can be shared by all countries. At wind shares above 100%, additional transmission capacity cannot further integrate more wind power generation: the grid capacity is reduced above 100% wind share and the remaining grid has a higher utilization. Transmission grid utilization is higher for high solar shares than for high wind shares, probably due to the fact that higher solar shares can only be integrated with storage and storage then provides balancing power and energy before transmission, thus enabling less fluctuating use of transmission lines.

While the amount of conventional capacity is influenced little by the CO_2 emission costs, the technology choice depends strongly on applied costs. By increasing the CO_2 price, a shift from coal-fired power plants with CCS to gas-fired power plants with CCS is observed.

Short term storage is mostly built for balancing solar power generation. The converter capacity installation of pumped hydro storage plants shows the reason for the current reluctance of German utilities to invest in pumped hydro storage capacities plans in Germany: at a solar penetration level of 10-15%, the capacity installation in our scenarios is lowest due to the fact that solar power generation tends to reduce the balancing needs by reducing the high midday power demand. At higher VRE shares, additional short term storage is built which mainly serves the integration of high solar shares: pumped hydro storage and battery capacities together reach 36% of peak load at 100% VRE penetration and 80% solar contribution.

Long term storage is only installed at high emission certificate costs and at theoretical VRE penetration levels between 60% and 120%. It is mostly built in wind dominated systems, since wind power has another temporal pattern than photovoltaic power generation. PV with its daily generation pattern assures a high number of storage cycles which suits batteries more than the less regular wind pattern, where surplus generation as well as calms can last days or even weeks. This temporal pattern suits longer term storage better. However, long term storage is expensive and thus hydrogen storage is only installed at high CO_2 emission certificate costs.

As the gross VRE generation is increased from 20% to 100% of load, the total average integration costs increase from 12 to 27 €/MWh_{VRE} in the medium CO_2 emission certificate price scenarios and a balanced solar-to-wind ratio. Wind-dominated scenarios see ~10% lower, solar-dominated scenarios see ~50% higher integration costs. The substantially higher integration costs for solar-dominated systems reflect the two facts that currently, the seasonal aggregated demand peak in the EU occurs in winter, and the daily demand-peak occurs in the evening (see (Ueckerdt et al., 2016), this issue). Thus, demand is not well correlated to solar generation, which has its seasonal maximum in summer and its daily maximum around noon. In other regions, the dependence of integration costs on the solar-to-wind ratio can be substantially different: As an example, rich countries in a hot climate with high usage of air conditioning have summer midday electricity demand peaks, which are well-correlated with solar generation, therefore integration costs for solar will be much lower.

Several factors can influence costs, backup energy and required amounts of backup, storage, and transmission capacity that have not been analysed in our study: e.g. higher European

CSP potentials or consideration of imports from North Africa, consideration of limited feasibility of CCS, a more nationally oriented power generation capacity distribution instead of a liberalised European structure, transmission capacity limits due to lack of acceptance and many other. These factors need to be further analysed. Additionally, a further splitting of VRE proportions, i.e. predefining the shares of CSP, PV, wind onshore and wind offshore power plants, would provide insights into required balancing measures and into cost deviations from the minimum due to technology choices.

The technology representation of conventional power plants used in this work does not account for technical restrictions in operational flexibility, for example arising from limited ramping velocities, minimum part-loads or long start-up times. An overestimation of power plant flexibility might cause an underestimation of curtailment and balancing needs. Due to the consideration of large model regions containing many power plants, this effect is, however, not as significant as it is for smaller assessment areas. Given the increasing contributions of VRE technologies to power supply, equipment manufacturers are focusing on an enhancement of the flexibility of thermal power plants. With an increasing future flexibility of conventional power plants, the approximations used in this paper appear more realistic (cp. (Brouwer et al., 2014)).

5 Conclusion

This paper offers a profound insight into least-cost European power supply structures at different shares and mixes of wind and solar power. Relying on a modelling approach in high temporal and spatial resolution, it provides detailed results concerning back-up, storage and capacities requirements, as well as VRE integration and average power generation costs. These findings can be used by IAMs for verifying their results.

Our study confirms earlier findings that substantially expanding the transmission grid is a cost-efficient option for integrating VRE. Power transmission is particularly important in supply systems dominated by wind power, and reaches an upper limit at a wind share of around 100%. In contrast, short-term electricity storage technologies (pumped hydro and batteries) are installed with much higher capacities in scenarios with high solar share. Higher CO_2 emission prices are found to cause an increase in grid and short-term storage capacity. Additionally, hydrogen storage is chosen as an integration measure at a high CO_2 price and especially at high wind shares. This implies that the potential of the grid as a cost-efficient option for the reduction of curtailments and thus integration of more VRE power generation is already largely exploited at medium CO_2 certificate price and that hydrogen storage only becomes a cost-efficient option to further reduce curtailments when this can no longer be achieved with transmission. It can furthermore be concluded that long term storage is a component of a cost-efficient power system only at high emission certificate prices.

According to the model results, the total conventional capacity can be as low as around 20% of peak load. This implies that the rest of the peak load is covered with renewable energy. Due to their integrated water or heat storage, reservoir hydro and CSP can provide firm capacity close to their nominal capacity. In contrast, other VRE require electrical energy storage with an overall capacity reaching more than one third of peak load. With increasing VRE shares, capacity factors of conventional power plants are found to decrease much stronger than the corresponding power generation capacities. Therefore, IAMs must take into account the VRE generation and curtailments in order to model the technology choice and thus the resulting emissions. Even though conventional power plants reach average capacity factors of only around 3% at close to 100% VRE share, they are proved to be competitive with additional storage or grid to provide peak power supply.

The REMix results show that CSP can be a cost-efficient component of a future European power system in terms of both a source of renewable energy and of balancing power and energy. Available potentials are not only exploited at high VRE shares, but as seen in (Scholz et al., 2016), also when CSP is a competitor of alternative dispatchable technologies.

Depending on the applied emission prices, least-cost supply systems are identified at different VRE shares. The minimum of the total system costs is shifted towards higher VRE shares with increasing CO_2 certificate price: it occurs at 40% theoretical VRE penetration in the low price, at 60% in a medium price and at 80% in high price scenarios. The costs are by 7-9% higher in solar dominated systems compared to systems dominated by wind or with equal shares of wind and solar.

Considering a balanced mix of solar and wind power, VRE integration costs identified by REMix increase from 12 €/MWh at 20% VRE share to 26 €/MWh at 80% VRE share. Wind-dominated scenarios show almost the same pattern, whereas solar-dominated scenarios have higher integration costs. At low VRE penetration the average integration costs are dominated by the utilization effect of power plants, while curtailment and storage become increasingly important at very high VRE shares. Local protests can hinder grid expansion, but more costly underground cables can increase social acceptance of grid expansion. Sensitivity runs with tripled grid costs show only a minor increase of integration costs. In contrast, if no grid connection at all is allowed between model regions, integration costs almost double. This underlines the significant role of grid expansion for cost-efficient VRE integration.

Acknowledgments

We are grateful to Carsten Hoyer-Klick for initiating and supporting this cooperation on the side of DLR and for his advice and support as a senior scientist. We also thank Denis Hess for sharing his knowledge about CSP and the critical discussions about systemic benefits of dispatchable and variable renewable power generation. Special thank goes to Dr. Falko Ueckerdt who gave very valuable advice concerning the setup of this study.

The work presented was funded by the EU commission as a part of the collaborative project 'ADVANCE', grant agreement No 308329.

References

Danish Energy Agency, Energinet.dk, 2012. Technology Data for Energy Plants. ISBNwww: 978-87-7844-931-3

Becker, S., Rodriguez, R.A., Andresen, G.B., Schramm, S., Greiner, M., 2014. Transmission grid extensions during the build-up of a fully renewable pan-European electricity supply. Energy 64, 404–418.

Brouwer, A.S., Broek, M. van den, Seebregts, A., Faaij, A., 2014. Impacts of large-scale Intermittent Renewable Energy Sources on electricity systems, and how these can be modeled. Renewable and Sustainable Energy Reviews 33, 443–466.

Gils, H.C., 2015. Balancing of Intermittent Renewable Power Generation by Demand Response and Thermal Energy Storage. Dissertation, University of Stuttgart.

Heide, D., Bremen, L. von, Greiner, M., Hoffmann, C., Speckmann, M., Bofinger, S., 2010. Seasonal optimal mix of wind and solar power in a future, highly renewable Europe. Renewable Energy 35, 2483–2489.

Hirth, L., Ueckerdt, F., Edenhofer, O., 2015. Integration costs revisited: An economic framework for wind and solar variability. Renewable Energy 74, 925–939.

Luderer, G., Krey, V., Calvin, K., Merrick, J., Mima, S., Pietzcker, R., Vliet, J. van, Wada, K., 2014. The role of renewable energy in climate stabilization: results from the EMF27 scenarios. Climatic Change 123, 427–441.

Nitsch, J., Pregger, T., Naegler, T., Heide, D., Trieb, F., Scholz, Y., Niehaus, K., Gerhardt, N., Sterner, M., Trost, T., von Oehsen, A., Schwinn, R., Pape, C., Hahn, H., Wickert, M., Wenzel, B., 2012. Langfristszenarien und Strategien für den Ausbau der erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europa und global. Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU).

Pietzcker, R.C., Stetter, D., Manger, S., Luderer, G., 2014. Using the sun to decarbonize the power sector: The economic potential of photovoltaics and concentrating solar power. Applied Energy 135, 704–720.

Pietzcker, R.C., Ueckerdt, F., Carrara, S., De Boer, H.-S., Després, J., Fujimori, S., Johnson, N., Kitous, A., Scholz, Y., Sullivan, P., Luderer, G., 2016. Evaluating the capacity of Integrated Assessment Models to represent system integration challenges of wind and solar power. Energy Economics, this issue.

Rasmussen, M.G., Andresen, G.B., Greiner, M., 2012. Storage and balancing synergies in a fully or highly renewable pan-European power system. Energy Policy 51, 642–651.
Rodriguez, R.A., Becker, S., Andresen, G.B., Heide, D., Greiner, M., 2014. Transmission needs across a fully renewable European power system. Renewable Energy 63, 467–476.
Rodriguez, R.A., Becker, S., Greiner, M., 2015. Cost-optimal design of a simplified, highly renewable pan-European electricity system. Energy 83, 658–668.
Schaber, K., Steinke, F., Hamacher, T., 2012. Transmission grid extensions for the integration of variable renewable energies in Europe: Who benefits where? Energy Policy 43, 123–135.
Schaber, K., Steinke, F., Mühlich, P., Hamacher, T., 2012. Parametric study of variable renewable energy integration in Europe: Advantages and costs of transmission grid extensions. Energy Policy 42, 498–508.
Scholz, Y., 2012. Renewable energy based electricity supply at low costs: development of the REMix model and application for Europe. Dissertation, University of Stuttgart.
Scholz, Y., Gils, H.C., Pregger, T., Heide, D., Cebulla, F., Cao, K.-K., Hess, D., Borggrefe, F., 2014. Möglichkeiten und Grenzen des Lastausgleichs durch Energiespeicher, verschiebbare Lasten und stromgeführte KWK bei hohem Anteil fluktuierender erneuerbarer Stromerzeugung. Bundesministerium für Wirtschaft und Energie (BMWi).
Scholz, Y., Gils, H.C., Pregger, T., Tena, D. Luca de, Heide, D., 2016. Integrated capacity expansion and operation modelling for variable renewable energy based power supply in Europe. Energy submitted, under review.
Stetter, D., 2014. Enhancement of the REMix energy system model: Global renewable energy potentials, optimized power plant siting and scenario validation. Dissertation, University of Stuttgart.
Sullivan, P., Krey, V., Riahi, K., 2013. Impacts of considering electric sector variability and reliability in the MESSAGE model. Energy Strategy Reviews 1, 157–163.
Tena, D. Luca de, 2014. Large Scale Renewable Power Integration with Electric Vehicles. Dissertation, University of Stuttgart.
Trieb, F., Schillings, C., Kronshage, S., Klann, U., Viebahn, P., May, N., Wilde, R., Paul, C., Kabariti, M., Bennouna, A., El Nokraschy, H., Hassan, S., Yussef, L.G., Hasni, T., El Bassam, N., Satoguina, H., 2006. Trans-Mediterranean Interconnection for Concentrating Solar Power: TRANS-CSP.
Trieb, F., Schillings, C., Pregger, T., O'Sullivan, M., 2012. Solar electricity imports from the Middle East and North Africa to Europe. Energy Policy 42, 341–353.
Ueckerdt, F., Hirth, L., Luderer, G., Edenhofer, O., 2013. System LCOE: What are the costs of variable renewables? Energy 63, 61–75.
Ueckerdt, F., Pietzcker, R.C., Luderer, G., Giannousakis, A., Scholz, Y., Stetter, D., 2016. Decarbonizing global power supply under region-specific consideration of challenges and options of integrating variable renewables in the REMIND model. Energy Economics, this issue.